Arthur D Little

Data Volume

Aggressive Use of Bioderived Products and Materials in the U.S. by 2010

October 2001

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Reference: 71038

EXECUTIVE ORDER 13134
DEVELOPING AND PROMOTING BIOBASED PRODUCTS AND BIOENERGY

By the authority vested in me as President by the Constitution and the laws of the United States of America, including the Federal Advisory Committee Act, as amended (5 U.S.C. App.), and in order to stimulate the creation and early adoption of technologies needed to make biobased products bioenergy cost-competitive in large national and international markets, it is hereby ordered as follows:

Section 1. Policy. Current biobased product and bioenergy technology has the potential to make renewable farm and forestry resources major sources of affordable electricity, fuel, chemicals, pharmaceuticals, and other materials. Technical advances in these areas can create an expanding array of exciting new business and employment opportunities for farmers, foresters, ranchers, and other businesses in rural America. These technologies can create new markets for farm and forest waste products, new economic opportunities for underused land, and new value-added business opportunities. They also have the potential to reduce our Nation's dependence on foreign oil, improve air quality, water quality, and flood control, decrease erosion, and help minimize net production of greenhouse gases. It is the policy of this Administration, therefore, to develop a comprehensive national strategy, including research, development, and private sector incentives, to stimulate the creation and early adoption of technologies needed to make biobased products and bioenergy cost-competitive in large national and international markets.

Sec. 2. Establishment of the Interagency Council on Biobased Products and Bioenergy.

(a) There is established the Interagency Council on Biobased Products and Bioenergy (the "Council"). The Council shall be composed of the Secretaries of Agriculture, Commerce, Energy, and the Interior, the Administrator of the Environmental Protection Agency, the Director of the Office of Management and Budget, the Assistant to the President for Science and Technology, the Director of the National Science Foundation, the Federal Environmental Executive, and the heads of other relevant agencies as may be determined by the Co-Chairs of the Council. Members may serve on the Council through designees. Designees shall be senior officials who report directly to the agency head (Assistant Secretary or equivalent

(b) The Secretary of Agriculture and the Secretary of Energy shall serve as Co-Chairs of the Council.

(c) The Council shall prepare annually a strategic plan for the President outlining overall national goals in the development and use of biobased products and bioenergy in an environmentally sound manner and how these goals can best be achieved through Federal programs and integrated planning.

(c) The goals shall include promoting national economic growth with specific attention to rural economic interests, energy security, and environmental sustainability and protection. These strategic plans shall be compatible with the national goal of producing safe and affordable supplies of food, feed, and fiber in a way that is sustainable and protects the environment, and shall include measurable objectives. Specifically, these strategic plans shall cover the following areas:

(1) biobased products, including commercial and industrial chemicals, pharmaceuticals, products with large carbon sequestering capacity, and other materials; and

(2) biomass used in the production of energy (electricity; liquid, solid, and gaseous fuels; and heat).

(d) To ensure that the United States takes full advantage of the potential economic and environmental benefits of bio-energy, these strategic plans shall be based on analyses of: (1) the economic impacts of expanded biomass production and use; and (2) the impacts on national environmental objectives, including reducing greenhouse gas emissions. Specifically, these plans shall include:

(1) a description of priorities for research, development, demonstration, and other investments in biobased products and bioenergy;

(2) a coordinated Federal program of research, building on the research budgets of each participating agency; and

(3) proposals for using existing agency authorities to encourage the adoption and use of biobased products and bioenergy and recommended legislation for modifying these authorities or creating new authorities if needed.

(e) The first annual strategic plan shall be submitted to the President within 8 months from the date of this order.

(f) The Council shall coordinate its activities with actions called for in all relevant Executive orders and shall not be in conflict with proposals advocated by other Executive orders.

Sec. 3. Establishment of Advisory Committee on Biobased Products and Bioenergy.

(a) The Secretary of Energy shall establish an "Advisory Committee on Biobased Products and Bioenergy" ("Committee"), under the Federal Advisory Committee Act, as amended (5 U.S.C. App.), to provide information and advice for consideration by the Council. The Secretary of Energy shall, in consultation with other members of the Council, appoint up to 20 members of the advisory committee representing stakeholders including representatives from the farm, forestry, chemical manufacturing and other businesses, energy companies, electric utilities, environmental organizations, conservation organizations, the university research community, and other critical sectors. The Secretary of Energy shall designate Co-Chairs from among the members of the Committee.

(b) Among other things, the Committee shall provide the Council with an independent assessment of:

(1) the goals established by the Federal agencies for developing and promoting biobased products and bioenergy;

(2) the balance of proposed research and development activities;

(3) the effectiveness of programs designed to encourage adoption and use of biobased products and bioenergy; and

(4) the environmental and economic consequences of biobased products and bioenergy use.

Sec. 4. Administration of the Advisory Committee.

(a) To the extent permitted by law and subject to the availability of appropriations, the Department of Energy shall serve as the secretariat for, and provide the financial and administrative support to, the Committee.

(b) The heads of agencies shall, to the extent permitted by law, provide to the Committee such information as it may reasonably require for the purpose of carrying out its functions.

(c) The Committee Co-Chairs may, from time to time, invite experts to submit information to the Committee and may form subcommittees or working groups within the Committee to review specific issues.

Sec. 5. Duties of the Departments of Agriculture and Energy. The Secretaries of the Departments of Agriculture and Energy, to the extent permitted by law and subject to the availability of appropriations, shall each establish a working group on biobased products and biobased activities in their respective Departments. Consistent with the Federal biobased products and bioenergy strategic plans described in sections 2(c) and (d) of this order, the working groups shall:

(1) provide strategic planning and policy advice on the Department's research, development, and commercialization of biobased products and bioenergy; and

(2) identify research activities and demonstration projects to address new opportunities in the areas of biomass production, biobased product and bioenergy production, and related fundamental research. The chair of each Department's working group shall be a senior official who reports directly to the agency head. If the Secretary of Agriculture or Energy serves on the Interagency Council on Biobased Products and Bioenergy through a designee, the designee should be the chair of the Department's working group.

Sec. 6. Establishment of a National Biobased Products and Bioenergy Coordination Office. Within 120 days of this order, the Secretaries of Agriculture and Energy shall establish a joint National Biobased Products and Bioenergy Coordination Office ("Office") to ensure effective day-to-day coordination of actions designed to implement the strategic plans and guidance provided by the Council and respond to recommendations made by the Committee.

All agencies represented on the Council, or that have capabilities and missions related to the work of the Council, shall be invited to participate in the operation of the Office. The Office shall:

(a) serve as an executive secretariat and support the work of the Council, as determined by the Council, including the coordination of multi-agency, integrated research, development, and demonstration ("RD&D") activities;

(b) use advanced communication and computational tools to facilitate research coordination and collaborative research by participating Federal and nonfederal research facilities and to perform activities in support of RD&D on biobased product and bioenergy development, including strategic planning, program analysis and evaluation, communications networking, information and data dissemination and technology transfer, and collaborative team building for RD&D projects; and

(c) facilitate use of new information technologies for rapid dissemination of information on biobased products and bioenergy to and among farm operators; agribusiness, chemical, forest products, energy, and other business sectors; the university community; and public interest groups that could benefit from timely and reliable information.

Sec. 7. Definitions. For the purposes of this order:

(a) The term "biomass" means any organic matter that is available on a renewable or recurring basis (excluding old-growth timber), including dedicated energy crops and trees, agricultural food and feed crop residues, aquatic plants, wood and wood residues, animal wastes, and other waste materials.

(b) The term "biobased product," as defined in Executive Order 13101, means a commercial or industrial product (other than food or feed) that utilizes biological products or renewable domestic agricultural (plant, animal, and marine) or forestry materials.

(c) The term "bioenergy" means biomass used in the production of energy (electricity; liquid, solid, and gaseous fuels; and heat).

(d) The term "old growth timber" means timber of a forest from the late successional stage of forest development. The forest contains live and dead trees of various sizes, species, composition, and age class structure. The age and structure of old growth varies significantly by forest type and from one biogeoclimatic zone to another.

Sec. 8. Judicial Review. This order does not create any enforceable rights against the Unites States, its agencies, its officers, or any person.

WILLIAM J. CLINTON

THE WHITE HOUSE,

August 12, 1999.

Appendix B. Executive Memorandum August 12, 1999, The White House

MEMORANDUM FOR: THE SECRETARY OF AGRICULTURE

THE SECRETARY OF ENERGY

THE SECRETARY OF THE TREASURY

THE ADMINISTRATOR OF THE ENVIRONMENTAL PROTECTION AGENCY

SUBJECT: Biobased Products and Bioenergy

Today I issued an Executive Order, "Developing and Promoting Biobased Products and Bioenergy," to further the development of a comprehensive national strategy that includes research, development, and private sector incentives to stimulate the creation and early adoption of technologies needed to make biobased products and bioenergy cost-competitive in national and international markets. Consistent with the objectives and activities in that order and to ensure that the Nation moves efficiently to exploit the benefits of expanded use of biobased products and bioenergy, I hereby direct as follows:

(1) The Secretaries of Agriculture and Energy, in consultation with other appropriate agencies, shall, within 120 days of this memorandum, prepare a report outlining and assessing options for modifying existing respective agency programs in fiscal year 2001 to pro-mote biobased products and bioenergy with a goal of tripling U.S. use of biobased products and bio-energy by 2010. Programs include, among others, conservation and utility programs within the Department of Agriculture (including the Conservation Reserve Program and the Environmental Quality Incentives Program); technology assistance and other small business programs; and education and extension programs. The report also shall include an assessment of: (a) the evidence to determine whether modifications to the tax code are a cost-effective policy option for review by the Department of the Treasury; and (b) the potential to expand use of biobased products and bioenergy by Federal agencies including co-firing with biomass at Federal facilities, use of biofuels in Federal vehicles, and Federal procurement of biobased products and bioenergy. Such expanded use shall be consistent with agency opportunities and the President's budget.

(2) In preparing this report, the agencies shall:

(a) work closely with the Environmental Protection Agency to ensure that actions recommended reflect a careful review of the environmental benefits, concerns, and net environmental consequences created by expanded use of biobased products and bioenergy. The factors considered should include:

(i) impact on net emissions of greenhouse gases including carbon sequestered by biomass crops, and substituting low net-carbon, biobased products, and bioenergy for products manufactured from fossil fuels; and

(ii) emissions of criteria pollutants and air toxics and other environmental consequences of production of biobased products and bioenergy; and

(iii) changes in water quality, soil erosion, pesticide and fertilizer use, and wildlife habitat as a consequence of changes in land use associated with biomass production; and,

(b) consider the findings and recommendations of the recently released National Academy of Sciences report "Biobased Industrial Products;" the recommendations contained in "Technology Vision 2020: The U.S. Chemical Industry" by the American Chemical Society, American Institute of Chemical Engineers, Chemical Manufacturers Association, Council for Chemical Research, and the Synthetic Organic Chemical Manufacturers Association; the recommendations by the U.S. agricultural, forestry, and chemical communities from the "Plant/Crop-based Renewable Resources 2020: A Vision to Enhance U.S. Economic Security Through Renewable Plant/Crop-Based Resource Use;" and, "Agenda 2020" by the U.S. Forest Products Industry; and

(c) consider input from other sources, including public-private strategic plans developed by the Departments of Agriculture and Energy, the Environ-mental Protection Agency, National Science Foundation, Department of the Interior, and other agencies bio-energy (power, fuels, and heat), commercial and industrial chemicals, and other products and materials.

(3) The Secretaries of Agriculture and Energy shall, within 120 days of this memorandum, report on outreach efforts to raise the Nation's awareness of the useful applications, benefits, and costs of producing bio-based products and bioenergy and adopting biobased technologies including workshops on new biomass crops and technologies for producing and marketing biobased products and bioenergy.

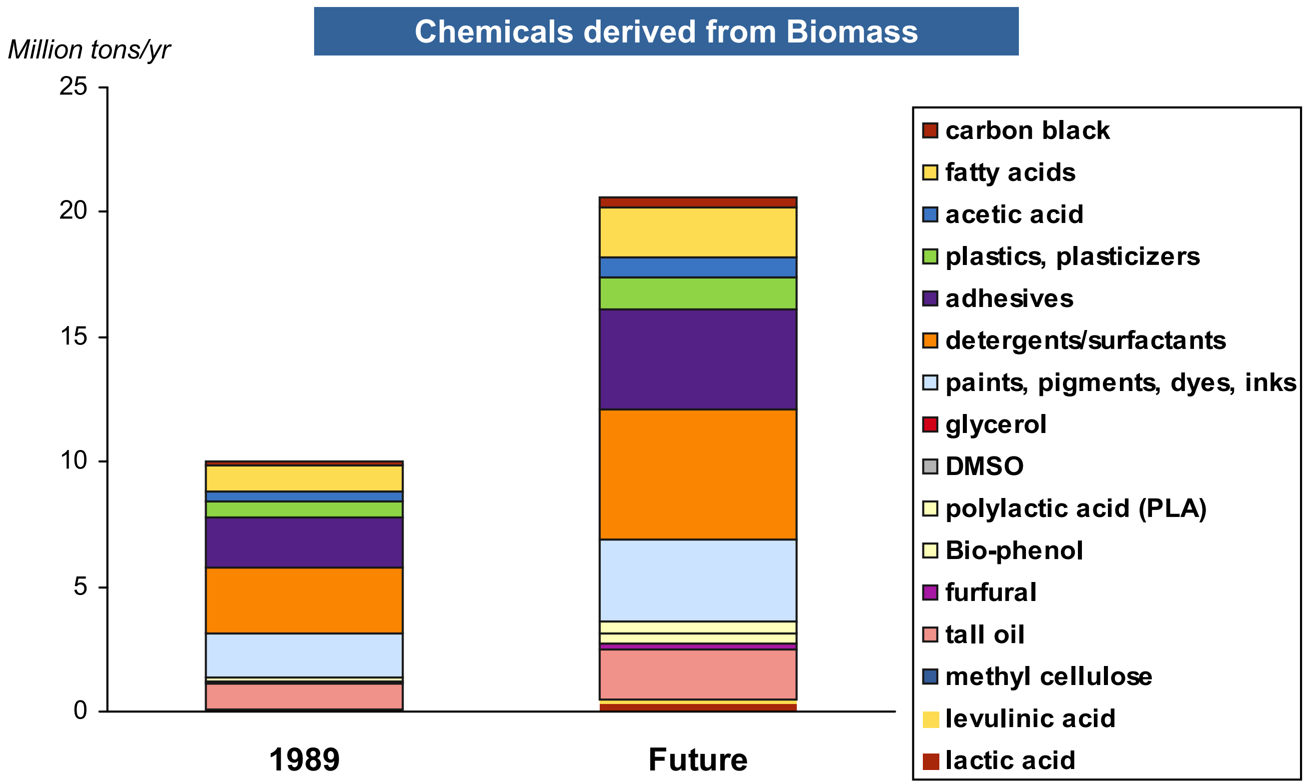
WILLIAM J. CLINTON

Sources for this data are listed below.

Product	Sources & Comments
Ethanol	• Energy Information Administration (EIA) website: • http://www.eia.doe.gov/cneaf/solar.renewables/alt_trans_fuel98/table10.html • Data for 1999: – 890,200,000 GGE[1] ethanol as a fuel oxygenate, – 2,489,000 GGE E85 (2,116,000 GGE ethanol) – 59,000 GGE E95 (56,000 GGE ethanol)
Other industrial products	• Ahmed & Morris, The Carbohydrate Economy, 1992
Pulp & Paper industry steam production	• Estimated that 100% of electricity production from wood & wood wastes is in pulp & paper industry, converted into electric power at 20% efficiency, with 80% of the waste heat recovered. • Difference between actual use of hog, bark and spent liquor solids as internal fuels and implied need at 20% generation efficiency is assumed to be converted directly into heat and used onsite. (Data from Manufacturing Consumption of Energy Survey, EIA)
Electricity production from wood & wood wastes	• EIA Renewable Energy Annual 1999
Electricity production from MSW	• EIA Renewable Energy Annual 1999
Electricity production from other biomass wastes	• EIA Renewable Energy Annual 1999

1. GGE: gallons gasoline-equivalent. Converted into gallons of ethanol at 129 MJ/gallon gasoline, 91 MJ/gallon ethanol (HHV)

Existing biomass derived chemicals are specialties for uses in solvents, inks, paints, adhesives, and specialty polymers.



Notes: Does not include ethanol by fermentation--included in alternative fuels. Growth in the chemicals is driven by introduction of new chemical building blocks for new biopolymers and building blocks for existing bulk chemical chains (e.g. BDO, diols), Future assumes doubling of "market share" of chemicals sourced from biomass feedstocks

Source: The Carbohydrate Economy, Institute for Local Self-Reliance, August 1992, USDOE OIT Project Descriptions, Manufacturer projections

The future scenario involves a doubling of the "market share" of biomass derived chemicals in each product group.

Property Assumptions

Fuel Specifications Table

Fuel	Unit	HHV (GJ)	Density (MT/unit)	HHV (GJ/MT)	Elemental composition C	H	O	S	N	K(ash)	Ca	Na	Si	MW kg/kmol	Carbon content g/GJ fuel	Carbon content kg/Unit	Max SO2 content g/GJ fuel
Acetaldehyde	1000 dry tons	24466	907	27.0	2.0	4.0	1.0	0.0	0.0		0.0			44.1	20219	494691	0
Acetic acid	1000 dry tons	13219	907	14.6	2.0	4.0	2.0	0.0	0.0		0.0			60.1	27453	362893	0
Acetol	1000 dry tons	18704	907	20.6	3.0	6.0	2.0	0.0	0.0	0.0	0.0			74.1	23593	441270	0
Activated carbon	1000 dry tons	30483	907	33.6	1.0									12.0	29760	907194	0
Ash	1000 dry tons	0	907	0.0							1.0			40.1	0	0	
Bio-diesel	million gallons	140220	3311	42.3	19.0	36.0	2.0	0.0	0.0					296.5	18176	2548664	0
Biogas - Landfill gas	MMSCF	826	17	48.4	1.0	4.0								16.0	15464	12778	0
Biogas - other residues	MMSCF	826	17	48.4	1.0	4.0								16.0	15464	12778	0
Biogas - sewage treatment	MMSCF	826	17	48.4	1.0	4.0								16.0	15464	12778	0
Biomass - corn	1000 bushels	487	22	22.3	1.0	1.8	0.9		0.0					28.5	18902	9203	0
Biomass - corn stover	1000 dry tons	16012	907	17.7	1.0	1.5	0.7	0.0	0.0	0.0				27.2	25052	401125	11
Biomass - Eucalyptus Grandis	1000 dry tons	17554	907	19.4	1.0	1.5	0.7	0.0	0.0	0.0				24.9	24969	438315	10
Biomass - maple	1000 dry tons	17110	907	18.9	1.0	1.5	0.7	0.0	0.0	0.0				24.1	26448	452509	32
Biomass - ponderosa pine	1000 dry tons	18162	907	20.0	1.0	1.4	0.7	0.0	0.0	0.0				24.4	24605	446882	30
Biomass - poplar	1000 dry tons	17581	907	19.4	1.0	1.4	0.7	0.0	0.0	0.0				24.7	25050	440416	10
Biomass - soybean	1000 bushels	458	27	16.8	1.0	1.5	1.0	0.0	0.0					29.5	24157	11064	0
Biomass - switchgrass	1000 dry tons	16717	907	18.4	1.0	1.5	0.7	0.0	0.0	0.0				25.6	25491	426131	84
Biomass - wheat straw	1000 dry tons	15885	907	17.5	1.0	1.4	0.7	0.0	0.0	0.1				27.0	25377	403114	129
Black liquor	1000 dry tons	14121	907	15.6	1.0	1.8	0.8	0.1	0.0	0.0				28.7	26874	379502	9008
Char	1000 dry tons	30483	907	33.6	1.0									12.0	29760	907194	0
CO2	1000 dry tons	0	907	0.0	1.0		2.0							44.0		247588	
Coal - Montana Dietz	1000 dry tons	26415	907	29.1	1.0	0.8	0.2	0.0	0.0	0.0				16.7	24711	652741	343
Coal - Pittsburgh #8	1000 dry tons	28757	907	31.7	1.0	0.8	0.1	0.0	0.0	0.0				15.9	23844	685686	1382
Corn oil	1000 dry tons	26212	907	28.9	1.0	0.6	0.0	0.0	0.0					13.2	31557	827171	462
Diesel	million gallons	143255	3142	45.6	1.0	1.8		0.0						13.8	19025	2725399	4
DME	million gallons	80400	2536	31.7	2.0	6.0	1.0							46.1	16447	1322339	0
DMM	million gallons	109965	3259	33.7	3.0	8.0	2.0							76.1	14033	1543168	0
E10	million gallons	125024	2832	44.1	1.1	2.2	0.1	0.0						17.1	18784	2353329	5
E85	million gallons	94662	2977	31.8	1.9	5.4	0.9	0.0	0.0					41.2	16945	1604065	1
E95	million gallons	90614	2996	30.2	2.0	5.8	1.0	0.0	0.0					44.5	17417	1578252	0
Electricity - industrial	GWh	3600	N/A	N/A										0.0	0	0	0
Ethanol - for blending	million gallons	88590	2988	29.7	2.0	6.0	1.0							46.1	17586	1557974	0
Ethanol - pure	million gallons	88590	2988	29.7	2.0	6.0	1.0							46.1	17586	1557974	0
Ethyl lactate	1000 dry tons	20794	907	22.9	5.0	10.0	3.0							118.1	22179	461191	0
Fatty acid	1000 dry tons	35737	907	39.4	18.0	34.0	2.0							282.5	19430	694363	0
fatty alcohol from soybean oil	1000 dry tons	39167	907	43.2	17.8	37.4	1.1							269.4	18388	720202	0
Fischer-Tropsch Diesel	1000 barrels	5812	122	47.7	16.0	34.0								226.4	17807	103491	0

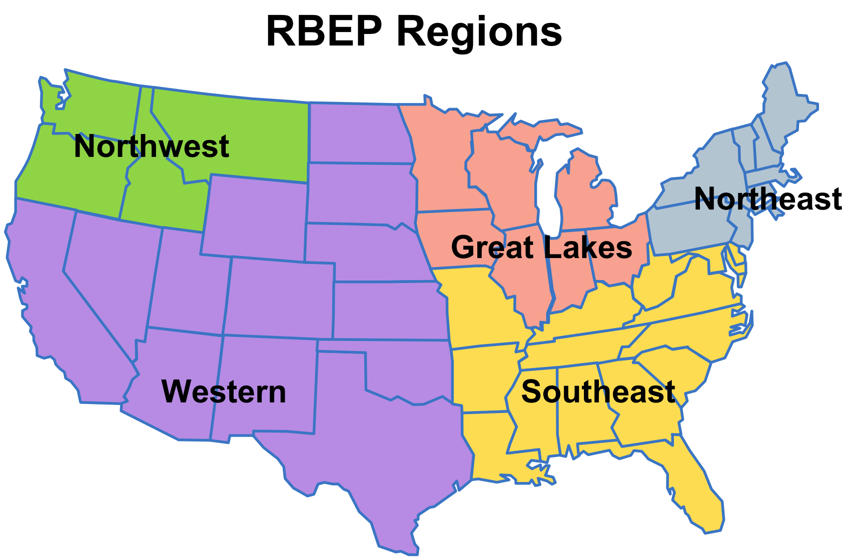
Property Assumptions

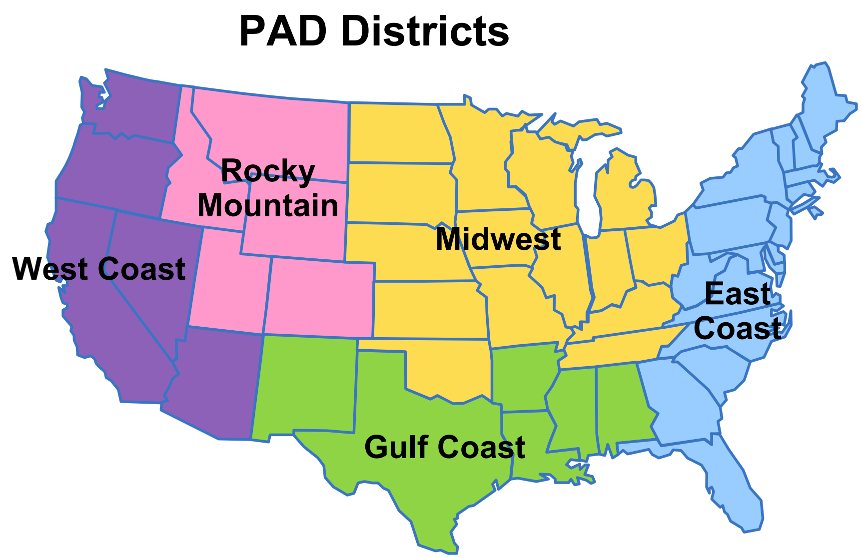
Fuel Specifications Table

		HHV	Density	HHV			Elemental composition							MW	Carbon content		Max SO2 content
Fuel	Unit	(GJ)	(MT/unit)	(GJ/MT)	C	H	O	S	N	K(ash)	Ca	Na	Si	kg/kmol	g/GJ fuel	kg/Unit	g/GJ fuel
Fischer-Tropsch Gasoline	million gallons	129072	2815	45.9	1.0	1.8	0.0							13.8	18920	2442094	0
Fischer-Tropsch Kerosene	1000 barrels	5633	117	47.9	11.0	24.0								156.3	17631	99311	0
Fischer-Tropsch Naphtha	1000 barrels	5166	107	48.5	7.0	16.0								100.2	17300	89380	0
Gasoline	million gallons	129072	2815	45.9	1.0	1.8		0.0						13.8	18917	2441702	7
Glycerin/Glycerol	1000 dry tons	16294	907	18.0	3.0	8.0	3.0							92.1	21785	354950	0
Gypsum	1000 dry tons	0	907	0.0			4.0	1.0			1.0			136.1	0	0	
Heavy Fuel Oil	1000 barrels	6547	153	42.9	1.0	1.6	0.0	0.0	0.0	0.0				13.7	20400	133562	64
Hogged fuel	1000 dry tons	17581	907	19.4	1.0	1.4	0.7	0.0	0.0	0.0				24.7	25050	440416	10
Hydrogen	MMSCF	342	2	141.8		2.0								2.0	0	0	0
Lactic acid	1000 dry tons	13717	907	15.1	3.0	6.0	3.0							90.1	26457	362893	0
Levoglucosan	1000 dry tons	15845	907	17.5	6.0	10.0	5.0	0.0	0.0		0.0			162.1	25447	403214	0
Low BTU gas	MMSCF	238	33	7.1	0.5	1.2	0.5		0.9		0.0			27.2	27900	6649	0
LPG	1000 barrels	4075	86	47.3	1.0	2.6								14.6	17419	70990	0
M85	million gallons	77468	2983	26.0	1.0	3.7	0.9	0.0	0.0					29.3	15779	1222370	1
M95	million gallons	71397	3003	23.8	1.0	3.9	1.0	0.0	0.0					31.1	16227	1158562	0
Methane	MMSCF	826	16	55.5	1.0	4.0								16.0	13491	11148	0
Methanol	million gallons	68362	3013	22.7	1.0	4.0	1.0							32.0	16521	1129376	0
MTBE	million gallons	106456	2812	37.9	5.0	12.0	1.0							88.1	17995	1915640	0
Municipal solid waste 1	1000 dry tons	18026	907	19.9	1.0	1.5	0.5	0.0	0.0					22.2	27222	490710	343
Naphtha	1000 barrels	5537	110	50.2	7.0	16.0								100.2	16725	92603	0
Natural Gas	MMSCF	1094	20	53.4	1.0	4.0	0.0	0.0	0.0					17.0	13716	15000	0
Other solid residues	1000 dry tons	17581	907	19.4	1.0	1.4	0.7	0.0	0.0	0.0				24.7	25050	440416	10
Petroleum	1000 barrels	6119	134	45.6	1.0	1.5		0.0	0.0					14.1	18642	114069	1665
Petroleum Coke	1000 dry tons	24636	907	27.2	1.0	0.4	0.1	0.0	0.0					14.7	30075	740929	805
Phenolics	1000 dry tons	21084	907	23.2	6.4	6.9	2.0				0.0			116.7	28549	601925	0
Propanediol (1,3)	1000 dry tons	21970	907	24.2	3.0	8.0	2.0							76.1	19553	429580	0
Pyrolysis oils	million gallons	82574	4542	18.2	1.0	1.5	0.7							24.1	27457	2267197	0
Refinery Gas	MMSCF	1323	26	51.7	1.4	4.7	0.0	0.0	0.0					21.6	15090	19962	0
Refuse derived fuel	1000 dry tons	15749	907	17.4	1.0	1.6	0.5	0.0	0.0					21.8	31728	499686	716
Reformulated gasoline	million gallons	128911	2749	46.9	1.0	2.1	0.0	0.0						14.3	17958	2315020	6
Sewage Sludge	1000 dry tons	15400	907	17.0	1.0	1.6	0.3	0.0	0.0	0.0	0.5			39.9	17715	272818	3052
Sludge	1000 dry tons	10977	907	12.1	1.0	1.7	0.5	0.1	0.0		0.5			43.7	22709	249279	10863
Soybean oil	1000 dry tons	36000	907	39.7	6.3	12.7	0.7							100.2	19137	688931	0
Sugars (modeled as sucrose)	1000 dry tons	14955	907	16.5	12.0	22.0	11.0				0.0			342.3	25542	381992	0
Synthetic Natural Gas	MMSCF	1185	22	54.5	1.2	4.2								18.1	14035	16631	0
Tires	1000 dry tons	31469	907	34.7	1.0	1.0	0.1	0.0	0.0		0.0			14.5	23918	752656	885
Waste Paper (non-recyclable)	1000 dry tons	24748	907	27.3	1.0	1.9	0.4	0.0	0.0		0.0			20.3	21672	536350	201

Note: MT = metric tonne, 1000 kg

Regions defined in the PAD districts do not match precisely to RBEP Regions





RBEP Region	Estimated as Average of PAD Regions
Great Lakes	Midwest
Northeast	East Coast
Northwest	West Coast, Rocky Mountain
Southeast	East Coast, Gulf Coast, Midwest
Western	West Coast, Rocky Mountain, Gulf Coast

We have applied a approximate averaging to capture this regional variation.

The following fuel prices for electric generators have been assumed for each of the RBEP regions.

RBEP Region	Natural Gas 2010 Reference Case	Coal 2010 Reference Case
Great Lakes	\$2.90/MSCF \$2.65/GJ[1]	\$26.3/ton \$1.00/GJ[2]
Northeast	\$3.47/MSCF \$3.17/GJ[1]	\$ 26.3/ton \$1.00/GJ[2]
Northwest	\$3.24/MSCF \$2.96/GJ[1]	\$ 26.3/ton \$1.00/GJ[2]
Southeast	\$3.27/MSCF \$2.99/GJ[1]	\$ 26.3/ton \$1.00/GJ[2]
Western	\$3.20/MSCF \$2.92/GJ[1]	\$ 26.3/ton \$1.00/GJ[2]
U.S. Average	\$3.08/MSCF \$2.82/GJ[1]	\$ 26.3/ton \$1.00/GJ[2]

1. From EIA Annual Energy Outlook 2010 Reference Case for Electric Generators. Table 84.
2. From EIA Annual Energy Outlook 2010 Reference Case for Electric Generators. Table C3.

The following fuel prices for industrial users have been assumed for each of the RBEP regions.

RBEP Region	Natural Gas 2010 Reference Case		Electricity 2010 Reference Case		Diesel 2010 Reference Case	
Great Lakes	$3.65/MSCF	$3.34/GJ[1]	¢3.77/kWh	$10.48/GJ[2]	$0.462/gallon	$3.22/GJ[3]
Northeast	$3.61/MSCF	$3.30/GJ[1]	¢4.49/kWh	$12.47/GJ[2]	$0.462/gallon	$3.22/GJ[3]
Northwest	$3.69/MSCF	$3.37/GJ[1]	¢3.62/kWh	$10.04/GJ[2]	$0.462/gallon	$3.20/GJ[3]
Southeast	$3.12/MSCF	$2.86/GJ[1]	¢3.89/kWh	$10.80/GJ[2]	$0.462/gallon	$3.20/GJ[3]
Western	$3.53/MSCF	$3.23/GJ[1]	¢3.65/kWh	$10.14/GJ[2]	$0.462/gallon	$3.20/GJ[3]
U.S. Average	$3.40/MSCF	$2.82/GJ[1]	¢3.84/kWh	$10.65/GJ[2]	$0.462/gallon	$3.20/GJ[3]

1. From EIA Annual Energy Outlook 2010 Reference Case for Industrial Users. Table 84.
2. From EIA Annual Energy Outlook 2010 Reference Case for Industrial Users. Tables 11-19.
3. From EIA Annual Energy Outlook 2010 Reference Case for Industrial Users. Table C3.

The following national average fuel prices for transportation have been assumed.

	Diesel 2010 Reference Case	Gasoline 2010 Reference Case	MBTE
U.S. Average	¢ 92.1/gallon $6.43/GJ[1]	¢90.7/gallon $7.03/GJ[1]	• Based on octane value and premium • '98-'00 average of $0.28 per octane point per barrel • $0.85 per gallon whole sale price for gasoline in 2010 with average octane of 89 • $41.4 to 46.0 per barrel MTBE

1. From EIA Annual Energy Outlook 2010 Reference Case for Transportation. Table 84.

Most modules use a 50/50 split of State of the Art and Uncontrolled emissions. Processing Modules use the State of the Art emissions factors.

	Uncontrolled Emissions								
Fuel/Technology	Carbon Content (g/GJ)	Sulfur Content (wt %)	Fuel HHV (MJ/kg)	SO2 (g/GJ input)	NOx (g/GJ input)	CH4 (g/GJ input)	NMHC (g/GJ input)	PM (g/GJ input)	CO (g/GJ input)
Diesel Train	19,017	0.05%	45.60	22.6	1,148.1	29.2	279.6	60.0	403.4
Fuel Oil Ship	20,285	0.14%	42.90	63.7	775.5	14.4	129.3	80.0	287.2
Diesel Truck	19,017	0.05%	45.60	22.6	700.0	4.1	70.0	40.0	70.0
Coal Boiler	31,557	1.33%	30.41	871.8	246.6	0.7	1.0	212.0	8.2
Coke Boiler	30,075	1.09%	27.16	805.9	214.1	0.0	2.8	227.3	28.5
Residual Oil Boiler	20,285	0.14%	42.90	63.7	160.0	2.9	0.8	32.9	14.5
Natural Gas Boiler	13,716	0.00%	53.42	0.3	41.5	1.0	4.6	3.2	34.8
Wood Boiler	25,100	0.02%	19.60	20.3	66.4	5.1	5.1	369.4	369.4
Diesel - IC Engine	19,017	0.05%	45.60	22.6	1,896.1	15.5	139.3	133.3	408.5
Distillate Oil - Turbine	19,017	0.10%	45.60	43.9	378.4	0.4	1.3	5.2	1.4
Natural Gas - IC Engine	13,716	0.00%	53.42	0.3	1,165.0	615.0	47.3	20.0	165.0
Natural Gas - Turbine	13,716	0.00%	53.42	0.3	137.6	3.7	1.0	2.8	35.3
HD Gasoline Vehicle	18,911	0.05%	45.85	21.8	400.0	5.0	100.0	0.4	500.0

Most modules use a 50/50 split of State of the Art and Uncontrolled emissions. Processing Modules use the State of the Art emissions factors.

	State of the Art Emissions								
Fuel/Technology	Carbon Content (g/GJ)	Sulfur Content (wt %)	Fuel HHV (MJ/kg)	SO2 (g/GJ input)	NOx (g/GJ input)	CH4 (g/GJ input)	NMHC (g/GJ input)	PM (g/GJ input)	CO (g/GJ input)
Diesel Train	19,017	0.05%	45.60	22.6	600.0	14.6	100.0	40.0	100.0
Fuel Oil Ship	20,285	0.14%	42.90	63.7	155.1	14.4	129.3	40.0	287.2
Diesel Truck	19,017	0.05%	45.60	22.6	350.0	4.1	70.0	6.7	70.0
Coal Boiler	31,557	1.33%	30.41	87.2	123.3	0.7	1.0	0.4	8.2
Coke Boiler	30,075	1.09%	27.16	80.6	132.2	0.9	1.9	0.2	8.2
Residual Oil Boiler	20,285	0.14%	42.90	6.4	16.0	2.9	0.8	0.3	14.4
Natural Gas Boiler	13,716	0.00%	53.42	0.3	8.3	2.9	0.8	0.0	15.7
Wood Boiler	25,100	0.02%	19.60	20.3	18.0	5.1	5.1	7.4	66.2
Diesel - IC Engine	19,017	0.05%	45.60	22.6	189.6	15.5	139.3	32.8	90.0
Distillate Oil - Turbine	19,017	0.10%	45.60	43.9	15.0	1.5	0.5	16.0	20.4
Natural Gas - IC Engine	13,716	0.00%	53.42	0.3	36.0	260.0	65.0	20.0	130.0
Natural Gas - Turbine	13,716	0.00%	53.42	0.3	3.8	3.7	1.0	2.8	3.6
HD Gasoline Vehicle	18,911	0.05%	45.85	21.8	100.0	5.0	44.0	0.4	400.0

Most modules use a 50/50 split of State of the Art and Uncontrolled emissions. Processing Modules use the State of the Art emissions factors.

	50/50 Split Emissions								
Fuel/Technology	Carbon Content (g/GJ)	Sulfur Content (wt %)	Fuel HHV (MJ/kg)	SO2 (g/GJ input)	NOx (g/GJ input)	CH4 (g/GJ input)	NMHC (g/GJ input)	PM (g/GJ input)	CO (g/GJ input)
Diesel Train	19,017	0.05%	45.60	22.6	874.0	21.9	189.8	50.0	251.7
Fuel Oil Ship	20,285	0.14%	42.90	63.7	465.3	14.4	129.3	60.0	287.2
Diesel Truck	19,017	0.05%	45.60	22.6	525.0	4.1	70.0	23.3	70.0
Coal Boiler	31,557	1.33%	30.41	479.5	185.0	0.7	1.0	106.2	8.2
Coke Boiler	30,075	1.09%	27.16	443.3	173.2	0.5	2.4	113.8	18.4
Residual Oil Boiler	20,285	0.14%	42.90	35.0	88.0	2.9	0.8	16.6	14.5
Natural Gas Boiler	13,716	0.00%	53.42	0.3	24.9	1.9	2.7	1.6	25.3
Wood Boiler	25,100	0.02%	19.60	20.3	42.2	5.1	5.1	188.4	217.8
Diesel - IC Engine	19,017	0.05%	45.60	22.6	1,042.8	15.5	139.3	83.0	249.2
Distillate Oil - Turbine	19,017	0.10%	45.60	43.9	196.7	1.0	0.9	10.6	10.9
Natural Gas - IC Engine	13,716	0.00%	53.42	0.3	600.5	437.5	56.2	20.0	147.5
Natural Gas - Turbine	13,716	0.00%	53.42	0.3	70.7	3.7	1.0	2.8	19.4
HD Gasoline Vehicle	18,911	0.05%	45.85	21.8	250.0	5.0	72.0	0.4	450.0

Most modules use a 50/50 split of State of the Art and Uncontrolled emissions. Processing Modules use the State of the Art emissions factors

Fuel/Technology	Uncontrolled Emissions
Diesel Train	2xDeLuchi (which were 50% of AP-42 emissions). PM - ADL estimate
Fuel Oil Ship	DeLuchi, 1993. PM - ADL Estimate
Diesel Truck	ADL Estimate
Coal Boiler	AP-42, Section 1.1, "Bituminous and subbituminous coal combustion", PC dry bottom, bituminous, tangentially fired
Coke Boiler	DeLuchi 1993, PM assumed to be same as coal per unit weight
Residual Oil Boiler	AP-42, Section 1.3, "Fuel oil combustion", #6 oil, <100 MMBtu/hour
Natural Gas Boiler	AP-42, Section 1.4, "Natural gas combustion", small industrial boilers <100 MMBtu/hr
Wood Boiler	AP-42, Section 1.6, "Wood Waste Combustion in Boilers", Wood/bark boilers @ 50% moisture fuel
Diesel - IC Engine	AP-42, Section 3.4, "Large stationary Diesel and All Stationary Dual Fuel Engines", NMHC/CH4 split estimated
Distillate Oil - Turbine	AP-42, Section 3.1, "Stationary Gas Turbines", CH4 assumed to be 25% of total HC
Natural Gas - IC Engine	2-cycle lean burn
Natural Gas - Turbine	AP-42, Section 3.1, "Stationary Gas Turbines", CH4 subtracted from total HC for NMHC
HD Gasoline Vehicle	ADL Estimate

Most modules use a 50/50 split of State of the Art and Uncontrolled emissions. Processing Modules use the State of the Art emissions factors

Fuel/Technology	State of the Art Emissions
Diesel Train	ADL estimate based on proposed regulations
Fuel Oil Ship	80% NOx reduction, 50% PM reduction
Diesel Truck	50% NOx reduction, 6x PM reduction
Coal Boiler	PC, dry bottom, tangentially fired, with reductions of 90% SO2, 50% NOx and 99.8% PM (baghouse).
Coke Boiler	Assumed to be the same as for coal per unit weight
Residual Oil Boiler	#6 oil industrial boilers with reductions of 90% SO2, 90% NOx (SCR) and 99.2% PM (ESP)
Natural Gas Boiler	Small industrial boilers 10-100 (MMBtu/hr) with reductions of 0% SO2, 80% NOx (FGR) and 99.2% PM (ESP).
Wood Boiler	Wood/bark-fired stoker boilers. Low range of AP-42 estimates (NOx and CO). 50% moisture wood. With reductions of 99.8% PM (ESP).
Diesel - IC Engine	Large (>600 hp) engines with 90% NOx reduction (SCR). CO ADL estimate
Distillate Oil - Turbine	Large GT for power generation with SCR (95%) and water injection
Natural Gas - IC Engine	2-cycle "clean burn" + SCR (90% reduction)
Natural Gas - Turbine	Large GT for power generation with SCR + water injection
HD Gasoline Vehicle	ADL Estimate

End Use Vehicle Emissions, gm/mile driven.

	CO2	SO2	NOx	CH4	NMHC	Part.	CO
Gasoline	315 [1.]	0.032 [2, 3.]	0.2 [6.]	0.006 [7, 8.]	0.04 [6.]	0.00 [11.]	1.7 [6.]
Reformulated Gasoline	299 [1.]	0.029 [2, 3.]	0.2 [6.]	0.006 [7, 9.]	0.04 [6.]	0.00 [11.]	1.7 [6.]
Ethanol - pure	266 [1.]	0.00 [2, 4.]	0.2 [6.]	0.008 [7, 9.]	0.04 [6.]	0.00 [11.]	1.7 [6.]
Ethanol - for blending	293 [1.]	0.00 [2, 4.]	0.2 [6.]	0.008 [7, 9.]	0.04 [6.]	0.00 [11.]	1.7 [6.]
Fischer-Tropsch Diesel	275 [1.]	0.00 [2, 4.]	0.2 [6.]	0.001 [7, 10.]	0.04 [6.]	0.04 [12.]	1.7 [6.]
DME	254 [1.]	0.00 [2, 4.]	0.2 [6.]	0.001 [7, 10.]	0.04 [6.]	0.04 [12.]	1.7 [6.]
Diesel	294 [1.]	0.015 [2, 5.]	0.2 [6.]	0.001 [7, 10.]	0.04 [6.]	0.04 [12.]	1.7 [6.]

1. CO2 emissions are calculated based on carbon content of fuel
2. SO2 emissions are calculated based on sulfur content of fuel
3. Sulfur content is 30 ppm from U.S. Environmental Protection Agency, Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Control Requirements, 40 CFR Parts 80, 85, and 86 (Washington, DC, February 10, 2000).
4. Sulfur content is 0 ppm for DME and FT-diesel since sulfur is removed prior to the synthesis of the fuel
5. Sulfur content is 15 ppm from U.S. Environmental Protection Agency, “Proposed Rules,” Federal Register, Vol. 65, No. 107, p. 35546 (June 2, 2000)
6. 50,000 mile durability ULEV standards for 2001-2006 Model Year for All PC’s and LDTs (0-3750 lbs LVW)
7. Methane is calculated by using test data to correlate the ratio of CH4 to NMHC, and multiplying this by the ULEV NMHC value.
8. Correlation based on NMHC emissions
9. CH4/ NMHC ratio from Light-Duty Alternative Fuel Vehicles: Federal Test Procedure Emissions Results, TP-25818. http://www.ott.doe.gov/otu/field_ops/pdfs/ethanol.pdf
10. CH4/NMHC ratio is 2% from Influence of Aldehyde and Hydrocarbon Components in the Exhaust on Exhaust Odor in DI Diesel Engines, SAE paper 2000-01-2820
11. Particulate emissions are taken as zero.
12. 100,000 mile durability standards for new 2001-2003 Model Year TLEV passenger cars and light duty trucks.

Process Type	Corn Farm

Products	Corn and corn stover

Estimated Performance Characteristics	
Efficiency (Based on HHV)	89.5%
Corn Yield	• Average U.S. corn yield 132.8 bushel/acre • Mass fraction of corn stover 0.45 dry lb/dry lb total corn plant • National average corn stover recovery 38% (dry lb recoverable per dry lb available on field)
Fossil energy use	0.10 GJ per GJ (corn plus corn stover)
Corn Properties	• Corn grain wet density 56 lb/bushel, • Corn grain dry density 49.3 lb/bushel • Corn grain moisture content 12%

Key Assumptions

- All costs and energy requirements are for the farm-gate. Separate modules address the transport of the biomass to the processing site
- All costs associated with farming are assumed to be reflected by the price of the corn and corn stover. Costs include capital recovery, equipment, maintenance, labor, fuel, and seed costs.
- The fossil fuels used in corn farming are accounted for in the emission calculation for the fuel chain.
- Estimates includes energy required for fertilizer production in addition to fuels used for farm equipment
- The corn stover and corn are assigned equal emissions on a energy (GJ) basis.

Other Inputs

Coal, Diesel, Grid electricity, gasoline, LPG, and Natural gas

Other Outputs

Corn stover, corn

References (see References section for complete citation)

- Corn production data from USDA NASS, http://www.usda.gov/nass/pubs/ranking/croprank.htm
- Price data from Agricultural Statistics Board, Crop Values, Feb 1999 (NASS/USDA)
- Corn and corn stover property data from personal correspondence with M. Walsh at Oak Ridge National Laboratory
- Energy embodied in fertilizer from DeLuchi, November 1993, % split from Marland and Turhollow, 1991
- Energy use on farms adapted from DeLuchi, 1993 (used 1987 data), data on corn farms
- Summary fertilizer use data by state, Updates on Agricultural Resource and Environmental Indicators (AREI), December 1997 (USDA Economic Research Service) Data located at http://www.ers.usda.gov:80/briefing/arei/newarei/

Process Type	Wheat Farm

Products	Wheat straw

Estimated Performance Characteristics	
Efficiency (Based on HHV)	83.5%
Wheat yield	• 40.7 bushels/acre (USDA statistics) • Mass fraction wheat straw 1.7 dry lb/dry lb wheat • National average wheat straw recovery 38%dry lbs recoverable/dry lb available on field (same as corn stover)
Fossil energy use	0.16 GJ per GJ wheat straw
Wheat Properties	• Wheat moisture content 13% • Wheat density 60 lb/bushel

Key Assumptions

- All costs and energy requirements are for the farm-gate.
- All costs associated with farming are assumed to be reflected by the price of the wheat straw.
- The fossil fuels used in farming are accounted for in the emission calculation for the fuel chain.
- Estimates includes energy required for fertilizer production in addition to fuels used for farm equipment
- The wheat straw and wheat are assigned equal emissions on a energy basis.

Other Inputs

Coal, Diesel, Grid electricity, gasoline, LPG, and Natural gas

Other Outputs

Wheat straw

References (see References section for complete citation)

- Personal correspondence with M. Walsh at Oak Ridge National Laboratory
- Energy embodied in fertilizer from DeLuchi, November 1993, % split from Marland and Turhollow, 1991
- Energy use on farms adapted from DeLuchi, 1993 (used 1987 data), data on corn farms
- Fertilizer use on farms: Updates on Agricultural Resource and Environmental Indicators (AREI), December 1997 (USDA Economic Research Service) Data located at http://www.ers.usda.gov:80/briefing/arei/newarei/
- Mass fraction of wheat straw for winter wheat (appears to be bulk of wheat harvest in USDA data -- Durum wheat is 1.3 tons/ton)
- Fraction of wheat straw recoverable assumed to be the same as for corn grain (M. Walsh's data on corn grain production)

Process Type	Switch grass Plantations

Products	Switch grass

Estimated Performance Characteristics	
Efficiency (Based on HHV)	94.4
Switchgrass yield	6 dry tons per acre per year
Fossil energy use	0.036 GJ per GJ switchgrass
Switchgrass Properties	

Key Assumptions

- All costs and energy requirements are for the farm-gate.
- Assume energy use is the same as on a SRIC poplar plantation. Total is from DeLuchi, breakdown assumes the same fuel distribution as corn farming.
- All costs associated with farming are assumed to be reflected by the price of the switchgrass.
- The fossil fuels used in farming are accounted for in the emission calculation for the fuel chain.
- Baseline fertilizer estimates from DeLuchi 1993, assuming that 1/2 of land is not fertilized
- Estimates includes energy required for fertilizer production in addition to fuels used for farm equipment

Other Inputs

Coal, Diesel, Grid electricity, gasoline, LPG, and Natural gas

Other Outputs

Switch grass

References (see References section for complete citation)

- Energy embodied in fertilizer from DeLuchi, November 1993, % split from Marland and Turhollow, 1991
- Deluchi Fertilizer Use on SRIC Plantations (1993)

Process Type	Poplar Plantations

Products	Poplar

Estimated Performance Characteristics	
Efficiency (Based on HHV)	94.4%
Poplar yield	6 dry tons per acre per year
Fossil energy use	0.036 GJ per GJ poplar
Poplar Properties	

Key Assumptions

- All costs and energy requirements are for the farm-gate.
- Total energy use is from DeLuchi for a SRIC plantation, breakdown assumes the same fuel distribution as corn farming.
- All costs associated with farming are assumed to be reflected by the price of the poplar.
- The fossil fuels used in farming are accounted for in the emission calculation for the fuel chain.
- Baseline fertilizer estimates from DeLuchi 1993, assuming that 1/2 of land is not fertilized
- Estimates includes energy required for fertilizer production in addition to fuels used for farm equipment

Other Inputs

Coal, Diesel, Grid electricity, gasoline, LPG, and Natural gas

Other Outputs

Poplar

References (see References section for complete citation)

- Energy embodied in fertilizer from DeLuchi, November 1993, % split from Marland and Turhollow, 1991
- Deluchi Fertilizer Use on SRIC Plantations (1993)

Process Type	Gaseous Biomass Produced On-site

Products	Landfill gas, Sewage gas, Digester gas

Key Assumptions

- Gaseous biomass is generated on the site on which it is processed. It is assumed that it is not transported by pressurized tanker or put into a new or existing gas pipeline. It is used primarily for power generation
- Landfill gas is converted to electricity on-site which is then exported to the grid.
- Sewage gas and digester gas are generated onsite at an industrial site. The power is generated onsite and used exclusively onsite. No power generated is exported to the grid

Process Type	Solid Waste Resources

Products	Refuse derived fuel (RDF), municipal solid wastes (MSW), Solid Sludges

Key Assumptions

- RDF and solid sludge are generated on the site on which it is processed. It is assumed that it is not transported by truck or by any other means.
- The fuels are used primarily for power production. The power is generated onsite and then exported to the grid.
- MSW is collected by truck.

Biomass Production Process Wastes

Process Type	Process Wastes

Products	Black Liquor, Hogged Fuel, Solid Residues

Key Assumptions
• All process waste resources are generated on the site on which it is processed. It is assumed that it is not transported by truck or by any other means. • The fuels are used primarily for power production. The power is generated onsite and used exclusively onsite. No power generated is exported to the grid.

Biomass Transportation On-Road Transport

Process Type	Biomass Transportation
Technology Type	50 mile truck (flat bed)

Applications	Corn stover, corn, wheat straw, switchgrass, poplar, MSW

Estimated Performance Characteristics	
Efficiency (Based on HHV)	98.2-99.2% depending on moisture content and heating value
Truck capacity	29 tons as delivered
Fossil energy use	0.01-0.02 GJ per GJ biomass
Economics	Capital cost $113 thousand Nonfuel operating cost $76 thousand/yr

Key Assumptions

- One way miles transported: 50 miles
- Truck fuel economy 6 mile per gallon, Diesel fueled
- Average biomass moisture content 50 percent for corn stover, corn, wheat straw, switchgrass, and poplar
- Corn capacity 460 thousand bushel per year
- Biomass capacity 11 thousand tons per year for corn stover, poplar, switchgrass, and wheat straw
- MSW moisture content 75 percent. Capacity for MSW is 6 thousand tons per year

Other Inputs

Diesel

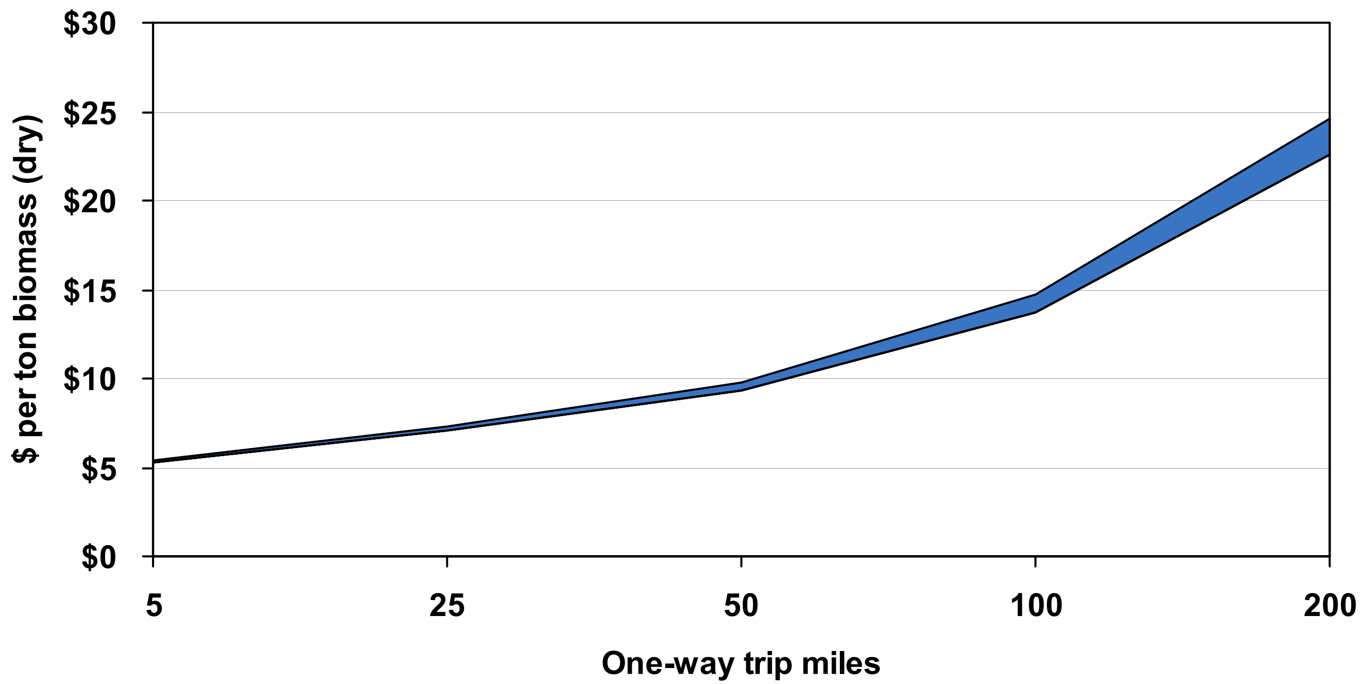
Other Outputs

None

References (see References section for complete citation)

- Truck capacity from Deluchi, 1993
- Average fuel economy of all combination trucks as reported in Davis, Stacey, Transportation Energy Databook Edition 19, Oak Ridge National Laboratory, September 1999.'
- Truck price from Jack Faucett & Associates, October, 1991 "Truck Size and Weight and User Fee Policy Analysis Study"

Transport of raw biomass to a transport facility is assumed to use a truck travelling 50 miles, based on considerations of product price as a function of distance.



Assumptions:
6 miles/gallon average fuel economy (from Transportation Energy Databook, volume 19)
$0.92-1.35/gallon diesel fuel
$1,000 maintenance cost per year, + $20 oil change every 5,000 miles
$50,000/year driver salary, + $25,000/year benefits, driver operates truck 3120 hours/year (60 hour weeks)
5 miles of each trip at local speeds, remainder at highway speeds. 2 hours of each trip spent loading/unloading
10 year truck life, lease rate 8% per year with 10% residual value at end of lease (.131 capital recovery factor)
$113,000 truck capital cost, 29 ton capacity

The economic and environmental impacts of the following 32 options were retained for the economic screen.

Technology P = Technology that has achieved market **P**enetration E = Technology in the market **E**ntry phase or in limited use D = **D**emonstration phase - not commercially available R&D = **R&D** phase - not yet demonstrated		Grid Power: Agricultural residues & energy crops*	Grid Power: Municipal Solid Waste (MSW	Grid Power: Refuse Derived Fuel (RDF)	Grid Power: Sewage Sludge	Grid Power: Biogas - Landfill gas	Onsite Power & CHP: Biogas - Sewage Treatment	Onsite Power & CHP: P&P - Black Liquor	Onsite Power & CHP: P&P - Hogged Fuel & Bark	Onsite Power & CHP: Other Solid Biomass Residues	Onsite Power & CHP: Biogas - Other Residues
Direct Combustion (solid biomass)	Biomass-only Rankine Cycle	P	P	P	E/P			P	P	P	
	Co-firing Rankine Cycle (coal)	E									
	Biomass-only Direct-Fired GT									---	
	Biomass-only Heat Only		---	---	---			---	---	---	
Gasification (solid biomass)	Biomass-only Rankine Cycle	D		D	D					E	
	Biomass-only GT/IGCC	D		R&D	R&D			R&D/D	R&D	R&D	
	Biomass-only ICE				R&D					E	
	Biomass-only Fuel Cell	R&D		R&D	R&D					R&D	
	Co-firing (coal or NG Rankine, IGCC, GTCC)	D/E		D	?						
Liquefaction (solid biomass)	Biomass-only Pyrolysis (Rankine, GT, ICE)	R&D		D	R&D				D	R&D	
	Co-firing with oil (Rankine, GT, ICE)	R&D		R&D	R&D				R&D	R&D	
Direct Combustion (gaseous biomass)	Biomass-only Rankine Cycle					E	?				?
	Co-firing Rankine Cycle (with natural gas)					---	---				---
	Biomass-only GT, GTCC, ICE					P	E/P				D/E
	Co-firing GT, GTCC, ICE (with natural gas)					---	---				---
	Biomass-only Fuel Cell					D/E	D/E				R&D
	Co-firing Fuel Cell (with natural gas)					---	---				---

Distribution of electricity and heat are assumed to carry no marginal capital costs.

Electricity

- U.S. average T&D efficiency is approximately 92.8%. (e.g., 92.8% of the kWh generated are delivered to the customer).
- As an average, this number is inherently variable, and tends to be lower for longer transport distances, or where the system is particularly constrained.
- Since resource constraints force biomass-power plants to be smaller than central power plants, it is difficult to predict whether additional capacity investments will be required (e.g., a plant may be located downstream of a supply bottleneck).
- In this analysis, we have assumed that there is no marginal capital cost for biopower transmission and distribution, and that it is delivered at the national average efficiency.

Heat

- Production of steam and/or hot water from biomass will face the same economics as production of heat from conventional fuels -- namely, that district energy-type distribution networks can render the system uneconomic.
- However, if the heat can be used on-site in a facility, it can be highly advantages to use an on-site biomass resource to produce heat by itself, or as a byproduct of electricity generation.
- In this analysis, we have assumed that there is no marginal capital cost for bio-derived heat, as it is most likely to be used in existing supply networks.

Process Type	Direct combustion of solid biomass
Technology Type	Biomass-only Rankine cycle

Application	Grid power
Fuel Type	Agricultural residues or energy crops

Estimated Performance Characteristics	
Capacity (MW)	60
Installed Capital Cost ($/kW)	$1,500
Net Electrical Efficiency (% LHV)	27%
Non-Fuel O&M Cost (¢/kWh)	1.3
Annual Capacity Factor	85%

Key Assumptions/Comments

- *Agricultural residues & energy crops* refers to wood and other biomass fuels purchased through existing channels as well as energy crops.
- Emissions of NO_x are controlled to 9ppm, consistent with new large-scale utility plants; SO_2 is based on AP-42 and is well below the NSPS standard; CH_4 emissions are uncontrolled; CO and NMHC emissions are based on AP-42; particulate emissions are based on a 99% reduction from uncontrolled levels according to NSPS.
- Fluidized bed boiler with steam turbine

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- *GPRA Review* 1999
- Energy Information Administration, 1997
- *AP-42* Table 1.6-1

Process Type	Direct combustion of solid biomass	**Application**	Grid power
Technology Type	Biomass-only Rankine cycle	**Fuel Type**	Municipal Solid Waste

Estimated Performance Characteristics	
Capacity (MW)	30
Installed Capital Cost ($/kW)	$2,800
Net Electrical Efficiency (% LHV)	19%
Non-Fuel O&M Cost (¢/kWh)	2.0
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx emissions are assumed to be 50% of uncontrolled levels (e.g., via SNCR and combustion modifications); SO2 emissions are controlled (30% of the uncontrolled level) and meet the NSPS standard; CH4 emissions are uncontrolled; CO emissions are uncontrolled; NMHC emissions are uncontrolled; particulate emissions are controlled to meet the NSPS standard of 0.03lb/MMBtu.
- Mass burn waterwall combustor with steam turbine

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- Energy Information Administration, 1997
- Harrison, 1997
- Integrated Waste Services Association, 2000
- *AP-42* Table 2.1-4

Process Type	Direct combustion of solid biomass
Technology Type	Biomass-only Rankine cycle

Application	Grid power
Fuel Type	Refuse Derived Fuel

Estimated Performance Characteristics	
Capacity (MW)	60
Installed Capital Cost ($/kW)	$1,800
Net Electrical Efficiency (% LHV)	27%
Non-Fuel O&M Cost (¢/kWh)	1.3
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx emissions are assumed to be 50% of uncontrolled levels (e.g., via SNCR and combustion modifications); SO2 emissions are controlled (30% of the uncontrolled level) and meet the NSPS standard; CH4 emissions are uncontrolled; NMHC emissions are uncontrolled; particulate emissions are controlled to meet the NSPS standard of 0.03lb/MMBtu.
- Fluidized bed RDF combustor with steam turbine
- Costs exclude the production facility for producing RDF

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- Energy Information Administration, 1997
- Harrison, 1997
- Integrated Waste Services Association, 2000
- *AP-42* Table 2.1-8

Process Type	Direct combustion of solid biomass		**Application**	Grid power
Technology Type	Biomass-only Rankine cycle		**Fuel Type**	Sewage Sludge

Estimated Performance Characteristics	
Capacity (MW)	30
Installed Capital Cost ($/kW)	$1,900
Net Electrical Efficiency (% LHV)	27%
Non-Fuel O&M Cost (¢/kWh)	1.3
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx emissions have NSCR controls; SO2 emissions are uncontrolled and based on AP-42; CH4, CO and NMHC emissions are uncontrolled (from AP-42); particulate emissions are controlled to meet the NSPS standard of 0.03lb/MMBtu
- Fluidized bed combustor with steam turbine

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:

- Energy Information Administration, 1997
- Harrison, 1997
- Integrated Waste Services Association, 2000
- *AP-42* Table 2.2-6
- *GPRA* Review, 1999

Process Type	Direct combustion of solid biomass
Technology Type	Biomass-only Rankine cycle

Application	Onsite power & CHP
Fuel Type	Pulp & Paper - Black Liquor

Estimated Performance Characteristics	
Capacity (MW)	80
Installed Capital Cost ($/kW)	$2,200
Net Electrical Efficiency (% LHV)	12%
Non-Fuel O&M Cost (¢/kWh)	0.8
Annual Capacity Factor	95%

Key Assumptions/Comments

- NOx emissions are uncontrolled; SO2 emissions are controlled using black liquor oxidation; CH4 emissions are uncontrolled; CO emissions are uncontrolled (AP 42);NMHC emissions are uncontrolled; particulate emissions are controlled to meet the NSPS standard of 0.03lb/MMBtu
- Thomlinson recovery boiler with steam turbine

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	20,020

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- Larson *et. al.* 1997
- Larson *et. al.* 1990
- Princeton, 1997
- *Pulp & Paper 1999-2000 North American Factbook*
- AP-42 Table 10.2-1

Biopower Direct Combustion *Hogged Fuel-Rankine Cycle*

Process Type	Direct combustion of solid biomass
Technology Type	Biomass-only Rankine cycle

Application	Onsite power & CHP
Fuel Type	Pulp & Paper - Hogged Fuel & Bark

Estimated Performance Characteristics	
Capacity (MW)	30
Installed Capital Cost ($/kW)	$1,900
Net Electrical Efficiency (% LHV)	27%
Non-Fuel O&M Cost (¢/kWh)	1.3
Annual Capacity Factor	90%

Key Assumptions/Comments

- NOx emissions are based on NSCR controls; SO2 emissions are uncontrolled (AP 42 data) and fall in well below NSPS standards; CH4 emissions are uncontrolled (AP 42); CO emissions are controlled to achieve 100ppm; NMHC are uncontrolled (AP-42); particulate emissions are controlled to meet the NSPS standard of 0.03lb/MMBtu
- Stoker boiler with steam turbine

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	7,381

References (see References section for complete citation)

ADL estimates based wholly or in part upon:

- Larson *et. al.* 1997
- AP-42 Table 1.6-1

Process Type	Direct combustion of solid biomass	**Application**	Onsite power & CHP
Technology Type	Biomass-only Rankine cycle	**Fuel Type**	Other Solid Biomass Residues

Estimated Performance Characteristics	
Capacity (MW)	10
Installed Capital Cost ($/kW)	$2,100
Net Electrical Efficiency (% LHV)	24%
Non-Fuel O&M Cost (¢/kWh)	1.3
Annual Capacity Factor	85%

Key Assumptions/Comments

- *Other solid biomass residues* are various residues produced from wood products and food products industries (e.g., sawdust, rice hulls, wood chips)
- NOx is assumed to be uncontrolled (no controls are required for a small scale plant); SO2 is uncontrolled (AP-42); CH4 is uncontrolled; CO emissions are controlled to achieve 100ppm; NMHCs are uncontrolled; particulate emissions are controlled to meet the NSPS standard of 0.03lb/MMBtu
- Stoker boiler with steam turbine

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	8,645

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- AP-42 Table 1.6-2
- *GPRA Review* 1999
- Energy Information Administration, 1997

Process Type	Direct combustion of solid biomass		**Application**	Grid power
Technology Type	Co-firing with Coal, Rankine cycle		**Fuel Type**	Agricultural residues & energy crops

Estimated Performance Characteristics	
Capacity (MW)	40
Installed Capital Cost ($/kW)	$136-$193
Net Electrical Efficiency (% LHV)	31.2%
Non-Fuel O&M Cost (¢/kWh)	0.45
Annual Capacity Factor	85%

Key Assumptions/Comments

- *Agricultural residues & energy crops* refers to wood and other biomass fuels purchased through existing channels, as well as energy crops.
- Capacity assumes 10% co-firing at a 400MW coal unit
- Performance characteristics are those associated with the biomass portion only
- Capital cost assumptions are overall averages based on the range of possible values for different types of coal plants in each of the five biomass supply regions.
- NOx emissions reductions for the entire plant are assumed to be 20% for 10% co-firing.

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- DOE EIA Electric Power Annual 1998, Volumes I & II
- AP-42, Section 1.1
- Plasynski, et al. 1999

Process Type	Gasification of solid biomass
Technology Type	Biomass-only Rankine cycle

Application	Grid power
Fuel Type	Agricultural residues & energy crops

Estimated Performance Characteristics	
Capacity (MW)	60
Installed Capital Cost ($/kW)	$1,700
Net Electrical Efficiency (% LHV)	27%
Non-Fuel O&M Cost (¢/kWh)	1.3
Annual Capacity Factor	85%

Key Assumptions/Comments

- *Agricultural residues & energy crops* refers to wood and other biomass fuels purchased through existing channels as well as energy crops.
- Emissions of NO_x are controlled to 9ppm, consistent with new large-scale utility plants; SO2, CO, CH4, NMHCs are uncontrolled; PM controlled to levels consistent with a natural gas boiler
- Direct gasification with gas boiler and conventional steam turbine

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:

- *GPRA Review 1999*
- Energy Information Administration, 1997
- Craig and Mann, 1997
- Mann and Spath, 1997
- Interlaboratory Working Group on Energy-Efficient and Low-Carbon Technologies, 1997

Process Type	Gasification of solid biomass
Technology Type	Biomass-only Rankine cycle

Application	Grid power
Fuel Type	Refuse Derived Fuel

Estimated Performance Characteristics	
Capacity (MW)	30
Installed Capital Cost ($/kW)	$2,000
Net Electrical Efficiency (% LHV)	27%
Non-Fuel O&M Cost (¢/kWh)	1.3
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx emissions are based on lean burn premix combustion (30% of the uncontrolled level); SO2 is reduced 99%; PM controlled to levels consistent with a natural gas boiler; all the rest (CO, CH4, NMHCs) are uncontrolled
- Direct gasification with gas boiler and steam turbine

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:

- *GPRA Review 1999*
- Energy Information Administration, 1997
- Craig and Mann, 1997
- Mann and Spath, 1997
- Interlaboratory Working Group on Energy-Efficient and Low-Carbon Technologies, 1997
- Integrated Waste Services Association, 2000

Process Type	Gasification of solid biomass		**Application**	Grid power
Technology Type	Biomass-only Rankine cycle		**Fuel Type**	Sewage Sludge

Estimated Performance Characteristics	
Capacity (MW)	30
Installed Capital Cost ($/kW)	$2,100
Net Electrical Efficiency (% LHV)	27%
Non-Fuel O&M Cost (¢/kWh)	1.3
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx emissions are based on lean burn premix combustion (30% of the uncontrolled level); SO2 is low and are uncontrolled; PM controlled to levels consistent with a natural gas boiler; all the rest (CO, CH4, NMHCs) are uncontrolled
- Direct gasification with gas boiler and steam turbine

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:

- *GPRA Review 1999*
- Energy Information Administration, 1997
- Craig and Mann, 1997
- Mann and Spath, 1997
- Interlaboratory Working Group on Energy-Efficient and Low-Carbon Technologies, 1997
- Integrated Waste Services Association, 2000

Process Type	Gasification of solid biomass	**Application**	Onsite power & CHP
Technology Type	Biomass-only Rankine cycle	**Fuel Type**	Other Solid Biomass Residues

Estimated Performance Characteristics	
Capacity (MW)	10
Installed Capital Cost ($/kW)	$2,400
Net Electrical Efficiency (% LHV)	27%
Non-Fuel O&M Cost (¢/kWh)	1.2
Annual Capacity Factor	85%

Key Assumptions/Comments

- *Other solid biomass residues* are various residues produced from wood products and food products industries (e.g., sawdust, rice hulls, wood chips)
- PM emissions are controlled to levels consistent with a natural gas boiler; all emissions are uncontrolled relative to a natural gas boiler
- Direct gasification with gas boiler and steam turbine

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	7,381

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- *GPRA Review 1999*
- Energy Information Administration, 1997
- Craig and Mann, 1997
- Mann and Spath, 1997
- Thermogenics, Inc., 1995
- Interlaboratory Working Group on Energy-Efficient and Low-Carbon Technologies, 1997

Process Type	Gasification of solid biomass		**Application**	Grid power
Technology Type	Biomass-only IGCC		**Fuel Type**	Agricultural residues & energy crops

Estimated Performance Characteristics	
Capacity (MW)	60
Installed Capital Cost ($/kW)	$1,500
Net Electrical Efficiency (% LHV)	39%
Non-Fuel O&M Cost (¢/kWh)	1.4
Annual Capacity Factor	85%

Key Assumptions/Comments

- *Agricultural residues & energy crops* refers to wood and other biomass fuels purchased through existing channels as well as energy crops.
- Emissions level for NOx and CO are controlled based on lean premix combustion (9 ppm NOx, 10ppm CO); SO2, CH4, NMHCs, and particulates are uncontrolled levels for a gas turbine (PM is assumed to be controlled to this level)
- Direct gasification with gas turbine combined cycle

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:

- Bain, *et. al.*, 1996
- *GPRA Review 1999*
- Energy Information Administration, 1997
- Craig and Mann, 1997
- Mann and Spath, 1997
- Interlaboratory Working Group on Energy-Efficient and Low-Carbon Technologies, 1997
- NCASI, 1997

Process Type	Gasification of solid biomass
Technology Type	Biomass-only IGCC

Application	Grid power
Fuel Type	Refuse Derived Fuel

Estimated Performance Characteristics	
Capacity (MW)	60
Installed Capital Cost ($/kW)	$1,800
Net Electrical Efficiency (% LHV)	39%
Non-Fuel O&M Cost (¢/kWh)	1.4
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx emissions are based on lean premix combustion (30% of the uncontrolled level); CO emissions are based on lean premix combustion (10ppm); SO2 is reduced 99%; CH4, NMHCs, and particulates are uncontrolled levels for a gas turbine (PM is assumed to be controlled to this level)
- Direct gasification with gas turbine combined cycle

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:

- Bain, *et. al.*, 1996
- *GPRA Review 1999*
- Energy Information Administration, 1997
- Craig and Mann, 1997
- Mann and Spath, 1997
- Interlaboratory Working Group on Energy-Efficient and Low-Carbon Technologies, 1997
- NCASI, 1997
- Fast Facts about Waste-to-Energy, 2000¢18/lb

Process Type	Gasification of solid biomass
Technology Type	Biomass- only IGCC

Application	Grid power
Fuel Type	Sewage Sludge

Estimated Performance Characteristics	
Capacity (MW)	30
Installed Capital Cost ($/kW)	$1,900
Net Electrical Efficiency (% LHV)	39%
Non-Fuel O&M Cost (¢/kWh)	1.4
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx emissions are based on lean premix combustion (30% of the uncontrolled level); CO emissions are based on lean premix combustion (10ppm); SO2, CH4, NMHCs, and particulates are uncontrolled levels for a gas turbine (PM is assumed to be controlled to this level)
- Direct gasification with gas turbine combined cycle

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:

- Bain, *et. al.*, 1996
- *GPRA Review 1999*
- Energy Information Administration, 1997
- Craig and Mann, 1997
- Mann and Spath, 1997
- Interlaboratory Working Group on Energy-Efficient and Low-Carbon Technologies, 1997
- NCASI, 1997
- Integrated Waste Services Association, 2000

Process Type	Gasification of solid biomass
Technology Type	Biomass-only IGCC

Application	Onsite power & CHP
Fuel Type	Pulp & Paper - Black Liquor

Estimated Performance Characteristics	
Capacity (MW)	80
Installed Capital Cost ($/kW)	$1,800
Net Electrical Efficiency (% LHV)	22%
Non-Fuel O&M Cost (¢/kWh)	1.4
Annual Capacity Factor	95%

Key Assumptions/Comments

- NOx emissions are based on lean premix combustion (30% of the uncontrolled level); CO emissions are based on lean premix combustion (10ppm); SO2 is reduced 99%; CH4, NMHCs, and particulates are uncontrolled levels for a gas turbine (PM is assumed to be controlled to this level)
- Direct gasification with gas turbine combined cycle

Other Inputs	
Diesel (gallons/ton biomass)	none

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	9,679

References (see References section for complete citation)

ADL estimates based wholly or in part upon:

- Bain, *et. al.*, 1996
- *GPRA Review 1999*
- Energy Information Administration, 1997
- Craig and Mann, 1997
- Mann and Spath, 1997
- Interlaboratory Working Group on Energy-Efficient and Low-Carbon Technologies, 1997
- NCASI, 1997
- Larson *et. al.* 1997
- Larson *et. al.* 1990
- Various, 1997
- *Pulp & Paper 1999-2000 North American Factbook*

Process Type	Gasification of solid biomass
Technology Type	Biomass-only IGCC

Application	Onsite power & CHP
Fuel Type	Pulp & Paper - Hogged Fuel & Bark

Estimated Performance Characteristics	
Capacity (MW)	30
Installed Capital Cost ($/kW)	$1,900
Net Electrical Efficiency (% LHV)	39%
Non-Fuel O&M Cost (¢/kWh)	1.4
Annual Capacity Factor	90%

Key Assumptions/Comments

- NOx and CO emissions are based on lean premix combustion; SO2, CH4, NMHCs, and particulates are uncontrolled levels for a gas turbine (PM is assumed to be controlled to this level)
- Direct gasification with gas turbine combined cycle

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	4,270

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- Bain, *et. al.*, 1996
- *GPRA Review 1999*
- Energy Information Administration, 1997
- Craig and Mann, 1997
- Mann and Spath, 1997
- Interlaboratory Working Group on Energy-Efficient and Low-Carbon Technologies, 1997
- NCASI, 1997
- Larson *et. al.* 1997

Process Type	Gasification of solid biomass	**Application**	Onsite power & CHP
Technology Type	Biomass-only GT	**Fuel Type**	Other Solid Biomass Residues

Estimated Performance Characteristics	
Capacity (MW)	10
Installed Capital Cost ($/kW)	$2,400
Net Electrical Efficiency (% LHV)	26%
Non-Fuel O&M Cost (¢/kWh)	1.1
Annual Capacity Factor	85%

Key Assumptions/Comments

- *Other solid biomass residues* are various residues produced from wood products and food products industries (e.g., sawdust, rice hulls, wood chips)
- NOx and CO emissions are based on lean premix combustion; SO2, CH4, NMHCs, and particulates are uncontrolled levels for a gas turbine (PM is assumed to be controlled to this level)
- Direct gasification with simple cycle gas turbine

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	7,770

References (see References section for complete citation)

ADL estimates based wholly or in part upon:

- *GPRA Review 1999*
- Energy Information Administration, 1997
- Craig and Mann, 1997
- Mann and Spath, 1997
- Interlaboratory Working Group on Energy-Efficient and Low-Carbon Technologies, 1997
- Thermogenics, Inc., 1995
- Arthur D. Little, Inc., 1999

Process Type	Gasification of solid biomass
Technology Type	Biomass- only ICE

Application	Grid power
Fuel Type	Sewage Sludge

Estimated Performance Characteristics	
Capacity (MW)	5
Installed Capital Cost ($/kW)	$1,600
Net Electrical Efficiency (% LHV)	32%
Non-Fuel O&M Cost (¢/kWh)	1.3
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx is based on 4-stroke lean burn ICE, SO2 is uncontrolled; particulates are uncontrolled levels for an ICE (PM is assumed to be controlled to this level); CO emissions are controlled to achieve 100ppm; CH4 and NMHCs are uncontrolled
- Direct gasification with IC engine

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:

- *GPRA Review 1999*
- Energy Information Administration, 1997
- Craig and Mann, 1997
- Mann and Spath, 1997
- Interlaboratory Working Group on Energy-Efficient and Low-Carbon Technologies, 1997
- Thermogenics, Inc., 1995
- MSB Energy Associates, 1995
- Arthur D. Little, Inc., 1999

Process Type	Gasification of solid biomass
Technology Type	Biomass-only ICE

Application	Onsite power & CHP
Fuel Type	Other Solid Biomass Residues

Estimated Performance Characteristics	
Capacity (MW)	5
Installed Capital Cost ($/kW)	$1,600
Net Electrical Efficiency (% LHV)	31%
Non-Fuel O&M Cost (¢/kWh)	1.3
Annual Capacity Factor	85%

Key Assumptions/Comments

- *Other solid biomass residues* are various residues produced from wood products and food products industries (e.g., sawdust, rice hulls, wood chips)
- NOx is based on 4-stroke lean burn ICE, SO2 is uncontrolled; particulates are uncontrolled levels for an ICE (PM is assumed to be controlled to this level); CO emissions are controlled to achieve 100ppm; CH4 and NMHCs are uncontrolled
- Direct gasification with IC engine

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	3,798

References (see References section for complete citation)

ADL estimates based wholly or in part upon:

- *GPRA Review 1999*
- Energy Information Administration, 1997
- Craig and Mann, 1997
- Mann and Spath, 1997
- Interlaboratory Working Group on Energy-Efficient and Low-Carbon Technologies, 1997
- Thermogenics, Inc., 1995
- MSB Energy Associates, 1995
- Arthur D. Little, Inc., 1999

Process Type	Gasification of solid biomass
Technology Type	Co-firing with coal - Rankine Cycle

Application	Grid power
Fuel Type	Agricultural residues & energy crops

Estimated Performance Characteristics	
Capacity (MW)	40
Installed Capital Cost ($/kW)	$500
Net Electrical Efficiency (% LHV)	25.6-26.9%
Non-Fuel O&M Cost (¢/kWh)	0.45
Annual Capacity Factor	85%

Key Assumptions/Comments

- *Agricultural residues & energy crops* refers to wood and other biomass fuels purchased through existing channels, as well as energy crops.
- Capacity assumes 10% co-firing at a 400MW coal unit
- Performance characteristics are those associated with the biomass portion only
- NOx reductions for the entire plant are assumed to be 40% for 10% co-firing, consistent with reburn technology.

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- DOE EIA Electric Power Annual 1998, Volumes I & II
- AP-42, Section 1.1
- Plasynski, et al. 1999

Process Type	Gasification of solid biomass
Technology Type	Co-firing with natural gas - GTCC

Application	Grid power
Fuel Type	Agricultural residues & energy crops

Estimated Performance Characteristics	
Capacity (MW)	40
Installed Capital Cost ($/kW)	$500
Net Electrical Efficiency (% LHV)	43.2%
Non-Fuel O&M Cost (¢/kWh)	0.3
Annual Capacity Factor	85%

Key Assumptions/Comments

- *Agricultural residues & energy crops* refers to wood and other biomass fuels purchased through existing channels, as well as energy crops.
- Capacity assumes 10% co-firing at a 400MW coal unit
- Performance characteristics are those associated with the biomass portion only
- Emissions are effectively those of the baseline GTCC unit, except for SO2, which are uncontrolled. PM from the biomass portion is assumed to be controlled to the same level as for the baseline GTCC.

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:

- AP-42, Section 3.1

Process Type	Liquefaction of solid biomass
Technology Type	Biomass-only pyrolysis (GT)

Application	Onsite power & CHP
Fuel Type	Other Solid Biomass Residues

Estimated Performance Characteristics	
Capacity (MW)	10
Installed Capital Cost ($/kW)	$3,100
Net Electrical Efficiency (% LHV)	17%
Non-Fuel O&M Cost (¢/kWh)	1.2
Annual Capacity Factor	85%

Key Assumptions/Comments

- *Other solid biomass residues* are various residues produced from wood products and food products industries (e.g., sawdust, rice hulls, wood chips)
- NOx emissions are based on lean premix combustion (30% of the uncontrolled level); all the rest (SO2, CO, CH4, NMHCs and particulates) are uncontrolled levels for the gas turbine.
- Fast pyrolyzer with simple cycle gas turbine
- All other by-products of pyrolysis (char, syngas) are assumed to be used for cogeneration

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	13,424

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- Bridgewater, 1999
- Arthur D. Little, Inc., 1999

Process Type	Liquefaction of solid biomass	**Application**	Onsite power & CHP
Technology Type	Biomass-only pyrolysis (ICE)	**Fuel Type**	Other Solid Biomass Residues

Estimated Performance Characteristics	
Capacity (MW)	10
Installed Capital Cost ($/kW)	$2,600
Net Electrical Efficiency (% LHV)	23%
Non-Fuel O&M Cost (¢/kWh)	1.5
Annual Capacity Factor	85%

Key Assumptions/Comments

- *Other solid biomass residues* are various residues produced from wood products and food products industries (e.g., sawdust, rice hulls, wood chips)
- NOx is based on NSPS standards of 0.5lb/MMBtu;CO emissions are controlled to achieve 100ppm; SO2, CH4 and NMHC are uncontrolled; particulate emissions are controlled to meet the NSPS standard of 0.03lb/MMBtu.
- Fast pyrolyzer with 4-stroke lean burn ICE
- All other by-products of pyrolysis (char, syngas) are assumed to be used for cogeneration

Other Inputs	
Diesel (gallons/ton biomass)	1.54

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	9,270

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- Bridgewater, 1999
- Arthur D. Little, Inc., 1999

Biopower Direct Combustion *Landfill Gas-Rankine Cycle*

Process Type	Direct combustion of gaseous biomass
Technology Type	Biomass-only Rankine cycle

Application	Grid power
Fuel Type	Biogas - Landfill gas

Estimated Performance Characteristics	
Capacity (MW)	15
Installed Capital Cost ($/kW)	$1,800
Net Electrical Efficiency (% LHV)	23%
Non-Fuel O&M Cost (¢/kWh)	1.1
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx is controlled to 9ppm based on lean premix; all the rest (SO2, CO, CH4, NMHCs and particulates) are uncontrolled
- Direct-fired gas boiler with steam turbine
- Costs exclude those for the Landfill gas collection system

Other Inputs	
None	

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:

- EPA, 1999
- EPA, 1996
- AP-42 Table 2.4-5

Process Type	Direct combustion of gaseous biomass	**Application**	Onsite power and CHP
Technology Type	Biomass-only Rankine cycle	**Fuel Type**	Biogas - Sewage Gas

Estimated Performance Characteristics	
Capacity (MW)	15
Installed Capital Cost ($/kW)	$1,800
Net Electrical Efficiency (% LHV)	23%
Non-Fuel O&M Cost (¢/kWh)	1.1
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx is controlled to 9ppm based on lean premix; all the rest (SO2, CO, CH4, NMHCs and particulates) are uncontrolled
- Direct-fired gas boiler with steam turbine
- Costs exclude those for the sewage treatment plant

Other Inputs	
None	

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	9,139

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- EPA, 1999
- EPA, 1996
- AP-42 Table 2.4-5

Process Type	Direct combustion of gaseous biomass	**Application**	Grid power
Technology Type	Biomass-only GT	**Fuel Type**	Biogas - Landfill gas

Estimated Performance Characteristics	
Capacity (MW)	5
Installed Capital Cost ($/kW)	$1,200
Net Electrical Efficiency (% LHV)	26%
Non-Fuel O&M Cost (¢/kWh)	0.8
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx is controlled to 9ppm based on lean premix; CO emissions are based on lean premix; all the rest (SO2, CH4, NMHC and particulates) are uncontrolled
- Direct-fired simple cycle gas turbine
- Costs exclude those for the Landfill gas collection system

Other Inputs	
None	

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- EPA, 1999
- EPA, 1996
- AP-42 Table 3.1-2
- Arthur D. Little, Inc., 1999

Process Type	Direct combustion of gaseous biomass		**Application**	Onsite power and CHP
Technology Type	Biomass-only GT		**Fuel Type**	Biogas - Sewage Gas

Estimated Performance Characteristics	
Capacity (MW)	5
Installed Capital Cost ($/kW)	$1,200
Net Electrical Efficiency (% LHV)	26%
Non-Fuel O&M Cost (¢/kWh)	0.8
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx is controlled to 9ppm based on lean premix; CO emissions are based on lean premix; all the rest (SO2, CH4, NMHC and particulates) are uncontrolled
- Direct-fired simple cycle gas turbine
- Costs exclude those for the sewage treatment plant

Other Inputs	
None	

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	7,770

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- EPA, 1999
- EPA, 1996
- AP-42 Table 3.1-2
- Arthur D. Little, Inc., 1999

Process Type	Direct combustion of gaseous biomass		**Application**	Onsite power and CHP
Technology Type	Biomass-only GT		**Fuel Type**	Biogas - Digester Gas & Other Gaseous Residues

Estimated Performance Characteristics	
Capacity (MW)	0.5
Installed Capital Cost ($/kW)	$1,000
Net Electrical Efficiency (% LHV)	26%
Non-Fuel O&M Cost (¢/kWh)	0.8
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx is controlled to 9ppm based on lean premix; CO emissions are based on lean premix; all the rest (SO2, CH4, NMHC and particulates) are uncontrolled
- Direct-fired microturbine
- Costs exclude methane generation (assumed to be required for other reasons, such as water discharges, environmental permitting and odor control)
- Example applications include confined animal feeding operation and wastewater treatment facilities at food processing plants.

Other Inputs	
None	

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	7,770

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- EPA, 1999
- EPA, 1996
- AP-42 Table 3.1-2
- Arthur D. Little, Inc., 1999

Process Type	Direct combustion of gaseous biomass		**Application**	Grid power
Technology Type	Biomass-only GTCC		**Fuel Type**	Biogas - Landfill gas

Estimated Performance Characteristics	
Capacity (MW)	15
Installed Capital Cost ($/kW)	$1,300
Net Electrical Efficiency (% LHV)	40%
Non-Fuel O&M Cost (¢/kWh)	1.0
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx is controlled to 9ppm based on lean premix; CO emissions are based on lean premix; all the rest (SO2, CH4, NMHC and particulates) are uncontrolled
- Direct-fired gas turbine combined cycle
- Costs exclude those for the Landfill gas collection system

Other Inputs	
None	

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- EPA, 1999
- EPA, 1996
- AP-42 Table 3.1-2
- NCASI, 1997

Process Type	Direct combustion of gaseous biomass	**Application**	Onsite power and CHP
Technology Type	Biomass-only GTCC	**Fuel Type**	Biogas - Sewage Gas

Estimated Performance Characteristics	
Capacity (MW)	15
Installed Capital Cost ($/kW)	$1,300
Net Electrical Efficiency (% LHV)	40%
Non-Fuel O&M Cost (¢/kWh)	1.0
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx is controlled to 9ppm based on lean premix; CO emissions are based on lean premix; all the rest (SO2, CH4, NMHC and particulates) are uncontrolled
- Direct-fired gas turbine combined cycle
- Costs exclude those for the sewage treatment plant.

Other Inputs	
None	

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	4,095

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- EPA, 1999
- EPA, 1996
- AP-42 Table 3.1-2
- NCASI, 1997

Process Type	Direct combustion of gaseous biomass
Technology Type	Biomass-only ICE

Application	Grid power
Fuel Type	Biogas - Landfill gas

Estimated Performance Characteristics	
Capacity (MW)	5
Installed Capital Cost ($/kW)	$1,100
Net Electrical Efficiency (% LHV)	35%
Non-Fuel O&M Cost (¢/kWh)	1.3
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx is based on a 4-stroke lean burn ICE; CO emissions are controlled to 100ppm; particulate emissions are controlled to meet the NSPS standard of 0.03lb/MMBtu; SO2, CH4 and NMHC are uncontrolled
- Direct-fired 4-stroke lean burn ICE
- Costs exclude those for the Landfill gas collection system

Other Inputs	
None	

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- EPA, 1999
- EPA, 1996
- AP-42 Table 2.4-5

Process Type	Direct combustion of gaseous biomass
Technology Type	Biomass-only ICE

Application	Onsite power and CHP
Fuel Type	Biogas - Sewage Gas

Estimated Performance Characteristics	
Capacity (MW)	5
Installed Capital Cost ($/kW)	$1,100
Net Electrical Efficiency (% LHV)	35%
Non-Fuel O&M Cost (¢/kWh)	1.3
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx is based on a 4-stroke lean burn ICE; CO emissions are controlled to 100ppm; particulate emissions are controlled to meet the NSPS standard of 0.03lb/MMBtu; SO2, CH4 and NMHC are uncontrolled
- Direct-fired 4-stroke lean burn ICE
- Costs exclude those for the sewage treatment plant.

Other Inputs	
None	

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	3,169

References (see References section for complete citation)

ADL estimates based wholly or in part upon:

- EPA, 1999
- EPA, 1996
- AP-42 Table 2.4-5
- AP-42 Table 3.1-1

Process Type	Direct combustion of gaseous biomass
Technology Type	Biomass-only ICE

Application	Onsite power and CHP
Fuel Type	Biogas - Digester Gas & Other Gaseous Residues

Estimated Performance Characteristics	
Capacity (MW)	1
Installed Capital Cost ($/kW)	$1,100
Net Electrical Efficiency (% LHV)	35%
Non-Fuel O&M Cost (¢/kWh)	1.3
Annual Capacity Factor	85%

Key Assumptions/Comments

- NOx is based on a 4-stroke lean burn ICE; CO emissions are controlled to 100ppm; particulate emissions are controlled to meet the NSPS standard of 0.03lb/MMBtu; SO2, CH4 and NMHC are uncontrolled
- Direct-fired 4-stroke lean burn ICE
- Costs exclude methane generation (assumed to be required for other reasons, such as water discharges, environmental permitting and odor control)
- Example applications include confined animal feeding operation and wastewater treatment facilities at food processing plants.

Other Inputs	
None	

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	3,169

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- EPA, 1999
- EPA, 1996
- AP-42 Table 2.4-5
- AP-42 Table 3.1-1

Process Type	Direct combustion of gaseous biomass		**Application**	Grid power
Technology Type	Biomass-only Fuel cell		**Fuel Type**	Biogas - Landfill gas

Estimated Performance Characteristics	
Capacity (MW)	1
Installed Capital Cost ($/kW)	$1,500
Net Electrical Efficiency (% LHV)	40%
Non-Fuel O&M Cost (¢/kWh)	1.3
Annual Capacity Factor	85%

Key Assumptions/Comments

- All emissions are uncontrolled but are inherently low (near zero)
- Costs exclude those for the Landfill gas collection system

Other Inputs	
None	

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	0

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- EPA, 1999
- EPA, 1996
- Arthur D. Little, Inc., 1999
- *GPRA Review 1999*

Process Type	Direct combustion of gaseous biomass	**Application**	Onsite power and CHP
Technology Type	Biomass-only Fuel cell	**Fuel Type**	Biogas - Sewage Gas

Estimated Performance Characteristics	
Capacity (MW)	1
Installed Capital Cost ($/kW)	$1,500
Net Electrical Efficiency (% LHV)	40%
Non-Fuel O&M Cost (¢/kWh)	1.3
Annual Capacity Factor	85%

Key Assumptions/Comments

- All emissions are uncontrolled but are inherently low (near zero)
- Costs exclude those for the sewage treatment plant

Other Inputs	
None	

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	4,095

References (see References section for complete citation)

ADL estimates based wholly or in part upon:
- EPA, 1999
- EPA, 1996
- Arthur D. Little, Inc., 1999
- *GPRA Review 1999*

Process Type	Direct combustion of gaseous biomass
Technology Type	Biomass-only Fuel cell

Application	Onsite power and CHP
Fuel Type	Biogas - Digester Gas & Other Gaseous Residues

Estimated Performance Characteristics	
Capacity (MW)	1
Installed Capital Cost ($/kW)	$1,500
Net Electrical Efficiency (% LHV)	40%
Non-Fuel O&M Cost (¢/kWh)	1.3
Annual Capacity Factor	85%

Key Assumptions/Comments

- All emissions are uncontrolled but are inherently low (near zero)
- Costs exclude methane generation (assumed to be required for other reasons, such as water discharges, environmental permitting and odor control)
- Example applications include confined animal feeding operation and wastewater treatment facilities at food processing plants.

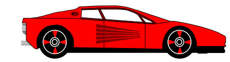
Other Inputs	
None	

Other Outputs	
Cogenerated Heat (Btu/kWh generated)	4,095

References (see References section for complete citation)

ADL estimates based wholly or in part upon:

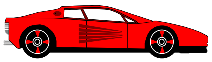
- EPA, 1999
- EPA, 1996
- Arthur D. Little, Inc., 1999
- *GPRA Review 1999*



The following options were retained for the economic screen analysis. (page 1 of 2)

Technology
P = Technology that has achieved market **P**enetration
E = Technology in the market **E**ntry phase
D = **D**emonstration phase - not commercially available
R&D = **R&D** phase - not yet demonstrated

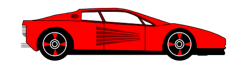
		Pure Fuel					Blending Agent				
Technology		Starch/Sugar Crops	Cellulosics	Municipal Solid Waste (MSW	Other Wastes	Seed Oils	Starch/Sugar Crops	Cellulosics	Municipal Solid Waste (MSW	Other Wastes	Seed Oils
Fermentation	Corn Ethanol (or other sugar feedstocks)	E					P				
	Cellulosic Ethanol from TVA process		D	D				D	D		
	Simultaneous saccharification (SSF) & co-fermentation;		D	R&D	R&D			D	R&D	R&D	
	Consolidated bio-processing		R&D	R&D	R&D			R&D	R&D	R&D	
	Syngas fermentation		R&D	R&D	R&D			R&D	R&D	R&D	
	Algal hydrogen production				R&D						
Pyrolysis	Thermal pyrolysis oils		R&D	R&D	R&D			R&D	R&D	R&D	
C1 Chemistry	Gasification and hydrogen synthesis	D*	D*	R&D	R&D						
	Gasification and synthetic natural gas synthesis	D*	D*	R&D	R&D						
	Gasification and methanol synthesis	D*	D*	R&D	R&D		D*	D*	R&D	R&D	
	Gasification and dimethyl ether synthesis	D*	D*	R&D	R&D						
	Gasification and dimethoxymethane synthesis	R&D	R&D	R&D	R&D		R&D	R&D	R&D	R&D	



The following options were retained for the economic screen analysis. (page 2 of 2)

		Pure Fuel					Blending Agent				
Technology		**Starch/Sugar Crops**	**Cellulosics**	**Municipal Solid Waste (MSW**	**Other Wastes**	**Seed Oils**	**Starch/Sugar Crops**	**Cellulosics**	**Municipal Solid Waste (MSW**	**Other Wastes**	**Seed Oils**
C1 Chemistry	**Gasification and Fischer-Tropsch diesel synthesis**	D*	D*	R&D	R&D		D*	D*	R&D	R&D	
	Gasification and Fischer-Tropsch Gasoline synthesis	D*	D*	R&D	R&D		D*	D*	R&D	R&D	
	Gasification and MTG synthesis	D*	D*	R&D	R&D		D*	D*	R&D	R&D	
	Gasification and Mixed Alcohol Synthesis	R&D	R&D	R&D	R&D		R&D	R&D	R&D	R&D	
Low temperature Processing	**Methyl esters(Biodiesel) from seed oils**				R&D	D				R&D	E

Biofuels Fermentation *Current Cellulosic SSCF Ethanol*



Process Type	Fermentation

Feedstock Types	Corn Stover, Wheat Straw, Switch Grass, Poplar
Technology Type	Simultaneous saccharification & co-fermentation (SSF); EtOH-baseline technology

Estimated Performance Characteristics

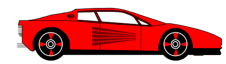
Feedstock	Nameplate capacity, MM gal. / year	GJ per year	Efficiency (HHV)	Lignin content	Capital Cost $MM	Operating Cost $MM per year	Pet. fuel $1000 / yr	Power Export
Corn Stover	48	4.1 MM	30.3%	17% (dry)	234	18.9	586	No
Wheat Straw	52	4.4 MM	36.6%	23% (dry)	234	18.9	547	35 GWh
Switchgrass	63	5.3 MM	32.6%	5.5% (dry)	234	18.9	682	No
Poplar	54	4.6 MM	33.6%	28% (dry)	234	18.9	547	92 GWh

Assumptions

- Maintenance estimated as 3 percent of sum of feed handling, pretreatment/Detox, SSCF, cellulase production, distillation, waste water treatment, boiler/turbogenerator and utilities
- General overhead estimated as 65 percent of sum of maintenance and direct labor
- Direct overhead estimated as 35 percent of direct labor
- 96 percent operating factor
- Emissions from processing are distributed proportionally between fuel produced and power exported on an energy basis.

References (see References section for complete citation)

- Lynd, Wyman and Gerngross, "Biocommodity Engineering" Biotechnol. Prog. **1999**, *15*, 777-793
- Wooley, Ruth, Sheehan,Ibsen, Majdeski and Galvez, Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrogenolysis Current and Futuristic Scenarios", NREL, July, 1999, Report No. NREL/TP-580-26157.
- Lynd, Elander, Wyman, “Likely Features and Cost of Mature Biomass Ethanol Technology”, Applied Biochemistry and Biotechnology, **1996**, *57/58*, 741



Process Type	Fermentation

Feedstock Types	Corn Stover, Wheat Straw, Switch Grass, Poplar
Technology Type	Simultaneous saccharification & co-fermentation (SSF); EtOH-2010 technology

Estimated Performance Characteristics

Feedstock	Nameplate capacity, MM gal. /year	GJ per year	Efficiency (HHV)	Lignin content	Capital Cost $MM	Operating Cost $MM per year	Pet. fuel $1000 / yr	Power Export
Corn Stover	64	5.5 MM	40.8%	17% (dry)	155	16.7	586	No
Wheat Straw	68	5.8 MM	47.7%	23% (dry)	155	16.7	547	35 GWh
Switchgrass	79	6.7 MM	41.0%	5.5% (dry)	155	16.7	682	No
Poplar	75	6.4 MM	48.9%	28% (dry)	155	16.7	547	92 GWh

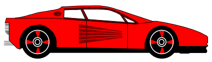
Assumptions

- Maintenance estimated as 3 percent of sum of feed handling, pretreatment/Detox, SSCF, cellulase production, distillation, waste water treatment, boiler/turbogenerator and utilities
- General overhead estimated as 65 percent of sum of maintenance and direct labor
- Direct overhead estimated as 35 percent of direct labor
- 96 percent operating factor
- Emissions from processing are distributed proportionally between fuel produced and power exported on an energy basis.

References (see References section for complete citation)

- Lynd, Wyman and Gerngross, "Biocommodity Engineering" Biotechnol. Prog. **1999**, *15*, 777-793
- Wooley, Ruth, Sheehan,Ibsen, Majdeski and Galvez, Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrogenolysis Current and Futuristic Scenarios", NREL, July, 1999, Report No. NREL/TP-580-26157.
- Lynd, Elander, Wyman, “Likely Features and Cost of Mature Biomass Ethanol Technology”, Applied Biochemistry and Biotechnology, **1996**, *57/58*, 741

Biofuels Fermentation *Ethanol from MSW*



Process Type	Chemical processing/fermentation

Feedstock Types	MSW
Technology Type	Ethanol production

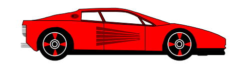
Estimated Performance Characteristics				
Feedstock	**GJ EtOH per year**	**Ethanol MM gallon/y**	**Co-Products Yield**	
MSW baseline	1.2 MM	13	Ash carbon dioxide Traditional recyclables Gypsum	67,000 dry tons 37,000 dry tons 22,000 dry tons 63,000 dry tons
MSW improved case	1.4 MM	15	Ash carbon dioxide Traditional recyclables Gypsum	67,000 dry tons 43,000 dry tons 22,000 dry tons 63,000 dry tons

Assumptions

- All mass and energy balances provided by Masada, Inc and are confidential.

References (see References section for complete citation)

Personal communication with D. Elliott of Masada. Details of the capital and operating costs provided are proprietary.



Process Type	Fermentation

Feedstock Types	Corn
Technology Type	Dry Mill Corn ethanol

Estimated Performance Characteristics

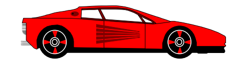
Feedstock	Nameplate capacity, MM gal. / year	GJ Ethanol per year	Efficiency (HHV)	Capital Cost $MM	Operating Cost $MM per year	Pet. fuel $1000 / yr	Co-Products	
Corn	100	8.9 MM	56.6%	156	23 does not include by-product credit	641	Distiller Dried Grains & Solubles	3.6 kg per gal ethanol

Assumptions

- Ethanol yield of 2.7 gallon per bushel corn
- Electricity use used An estimate of the best current practice, which should be fairly representative of the average plant in the year 2000, which could be a reasonable estimate of industry average in the year 2000.
- GRI (1994) estimated that ethanol represents 75% of the energy output from the plant.
- Efficiency is based on heating value of all products and all inputs

References (see References section for complete citation)

- Ethanol Distillery - Wet Milling Process Source: Marland and Turhollow, 1991
- Capex from Wood, 1993



Process Type	C_1 Chemistry-Syngas Based

Feedstock Types	Corn Stover, Wheat Straw, Switch Grass, Poplar
Technology Type	Fischer-Tropsch Synthesis

Estimated Performance Characteristics

Feedstock	GJ Product per year	Efficiency (HHV)	Diesel Thous. Barrel/year	Naphtha Thous. Barrel / year	Capital Cost $MM	Operating Cost $MM per year	Pet. fuel $1000 / yr
Corn Stover	4.7 MM	48.1%	573	258	280	15.4	0
Wheat Straw	4.6 MM	47.7%	569	256	280	15.4	0
Switchgrass	4.8 MM	47.8%	595	267	280	15.4	0
Poplar	5.0 MM	46.8%	614	274	280	15.4	0

Assumptions

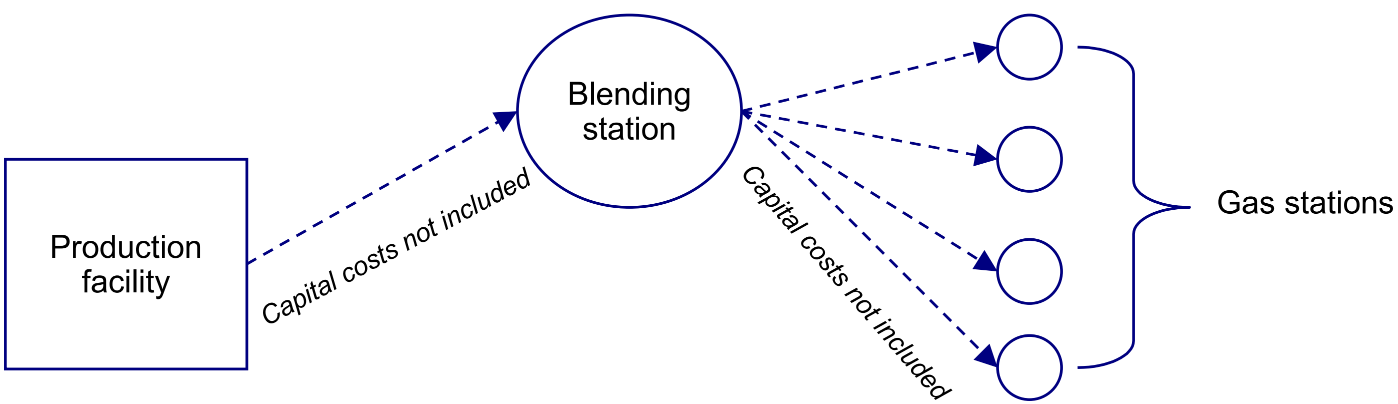
- Maintenance estimated as 3 percent of fixed capital investment; General overhead estimated as 65 percent of sum of maintenance and direct labor; Direct overhead estimated as 35 percent of direct labor; 91.3 percent operating factor
- Contingency 25% of fixed capital; Owners cost, fee, profit 10% of fixed capital; Working capital 10% of fixed capital
- FT synthesis loop 20% more capital investment than methanol synthesis loop capital investment. FT-biomass 25% more capital investment in utilities/auxiliaries than methanol biomass plant (additional hydroisomerization plant is required).
- Assume that kerosene production is split 95:05 between FT diesel and naphtha production; Plant uses sulfur free FT-diesel internally as diesel fuel
- BCL Gasifier with an efficiency of 80.1 percent; FT synthesis loop 60 percent efficient. Just enough syngas is assumed to be diverted for electricity production
- No petroleum fuel is needed to transfer biomass within plant as output FT diesel can be used.
- Emissions from processing are distributed proportionally between FT diesel and FT naphtha on an energy basis.

References (see References section for complete citation)

- Katofsky Thesis, 1993 for capital and operating cost estimates for biomass methanol that were adapted for FT synthesis
- Williams, Larson, Katofsky and Chen, 1995 for energy balance of methanol plant, adapted for FT synthesis loop
- Borgwardt, “Methanol Production from Biomass and Natural Gas as Transportation Fuel”, Ind. Eng. Chem. Res., **1998**, *37*, 3760-3767
- FT product split projected from ADL database of proprietary natural gas based plants
- Larson and Jin, in 4th Biomass Conference of the Americas, Oakland, CA, 1999 for FT product composition from biomass
- CPI adjustment statistics from Bureau of Labor Statistics website, http://stats.bls.gov/

Distribution of some fuels can "piggyback" on the existing infrastructure.

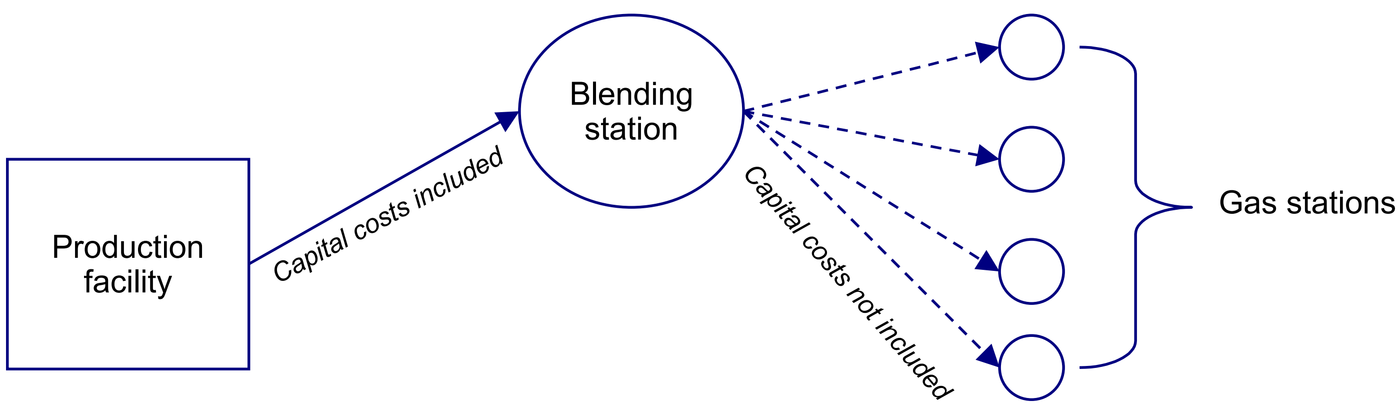
FT diesel	• FT diesel is fungible with petroleum derived diesel, and can therefore use the existing distribution infrastructure. • Understanding the capital costs associated with marginal increases in diesel fuel use would require a bottleneck-analysis that is beyond the scope of this assignment. • For the purposes of this analysis, it has been assumed that FT diesel has no marginal capital cost associated with distribution.



Distribution of some fuels can "piggyback" on part of the existing infrastructure.

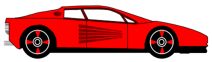
Blended Ethanol

- Understanding the capital costs associated with marginal increases in fuel use would require a bottleneck-analysis that is beyond the scope of this assignment.
- For the purposes of this analysis, it has been assumed that blended ethanol has no marginal capital cost associated with distribution from the blending station to the customer
- Capital costs have been factored in for transportation from the production facility to the blending center.



Distribution of some fuels will require the construction of dedicated product pipelines.

Pure Ethanol	• Water solubility will absorb impurities from (or leave deposits in) pipelines designed for petroleum-based fuels. Shipments of pure ethanol are therefore likely to require dedicated distribution networks of trucks, pipelines and railcars.
Blended Ethanol	• Fuel is assumed to be transported via pipeline to a storage terminal/blending station, but subsequent distribution of gasoline/ethanol mixes is assumed to use existing gasoline distribution network.
Synthetic natural gas	• Assumed to be fungible with conventional natural gas distribution infrastructure, so no marginal costs or emissions are associated with distribution
Hydrogen	• Pressure requirements mandate dedicated pipelines, trucks, etc.
DME	• Pressure requirements mandate dedicated pipelines, trucks, etc.



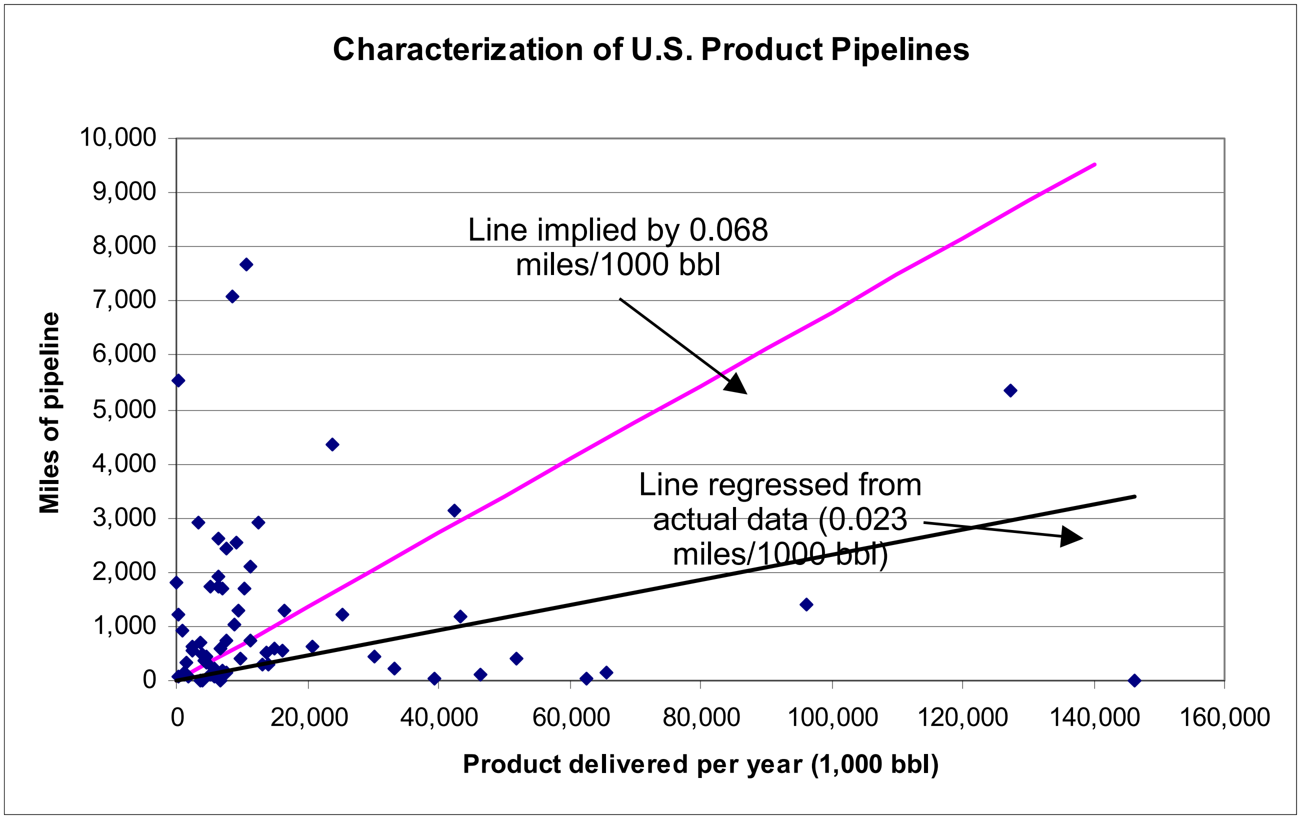
Estimations of required pipeline construction for those fuels which cannot use the existing network can be estimated from the installed product pipeline base in the U.S.

Total miles of product pipelines in the US[a]	81,137
Total annual trunkline traffic, million bbl-miles[a]	1,667,721
Implied deliveries, 1000 bbl/year	1,192,852[b]
Implied pipeline requirements, miles/1000 bbl	0.068

[a] Source: True, Warren, "U.S. pipelines experience another tight year, reflect merger frenzy", *Oil & Gas Journal*, August 23, 1999.

[b] Calculation of implied deliveries based on pipeline-by-pipeline division of bbl-miles traffic/total miles of pipeline. Note that this calculation is mathematically incorrect if done on the total miles of pipe and total trunkline traffic, and therefore does not directly result from the values in this table.

There is a broad spread of data around the 0.068 miles/1000 bbl mean, and the slope of a regressed line through the data is a lower 0.023 miles/1000 bbl.



We have used the higher value in our analysis, recognizing that biomass facilities are more likely to be in rural areas with longer routes to market.

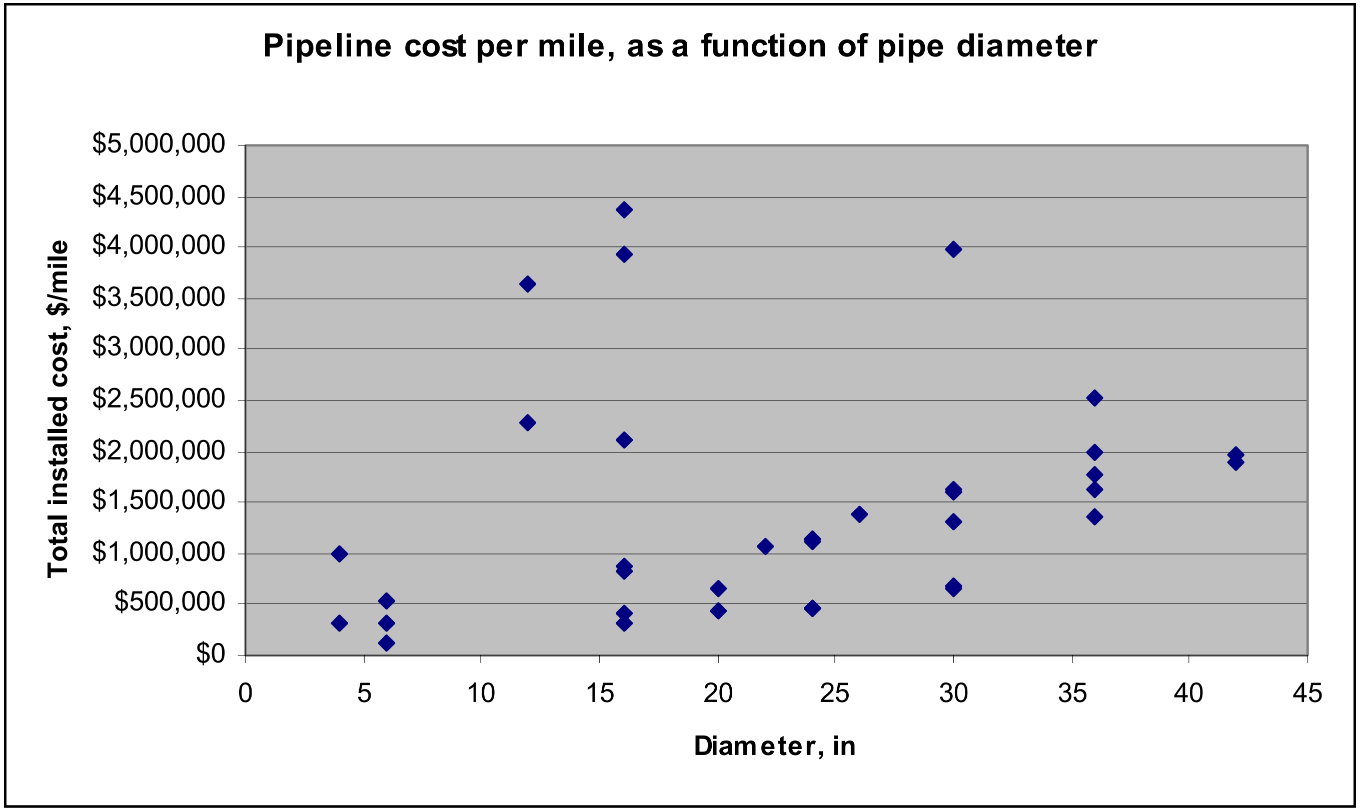
Actual piping distances are expected to be higher in less populous areas; we have estimated the impact of this distance by scaling pipe length with population density.

- Conventional pipelines connect refineries to population hubs, which tend to be fairly close together.
- Biomass refineries are expected to be further from population hubs, since biomass supply is in more rural regions.
- We have assumed that the most population dense region (Northeast) will require a pipe distance per bbl of fuel transported comparable to existing petroleum-product pipelines; other regions are scaled with the square root of their area/person relative to the Northeast (e.g., linear with the radius of an equivalent circle).

Region	Population density (people/sq mile)	Estimated pipe distances (miles/1000 bbl)
Great Lakes	117.14	0.108
Northeast	292.96	0.068
Northwest	28.13	0.219
Southeast	121.97	0.105
Western	53.76	0.159

Population data from U.S. Census 1999 estimates, http://www.census.gov/datamap/www/
Area data from National Geographic online data, http://www.nationalgeographic.com/resources/ngo/maps/

While average pipeline costs are $1,234,000/mile, there is a broad spread in this data, and can be considerably lower for small-diameter pipes.



Source: True, Warren, “U.S. pipelines experience another tight year, reflect merger frenzy”, *Oil and Gas Journal*, August 23, 1999.

Since biomass facilities are not expected to be as large as conventional refineries, we have assumed a pipe cost of $500,000/mile.

Operating costs for pipelines as a fraction of installed capital have been estimated based on publicly available FERC submissions.

1998 Annual Data For All Product Pipelines	Cost, $1,000	Comments
Operating Revenue	$4,317,295	
Income	$1,482,709	
Implied Operating Costs	$2,834,586	Revenue - Income
Estimated Total Capital Expenditure	$100,161,436	Estimated based on average costs for all pipes of $1,234,473/mile and 81,137 miles of product pipeline
Operating Costs, as a fraction of Capital Expenditure	**2.83%**	Operating costs/installed capital cost. Note that this includes fuel and non-fuel operating costs

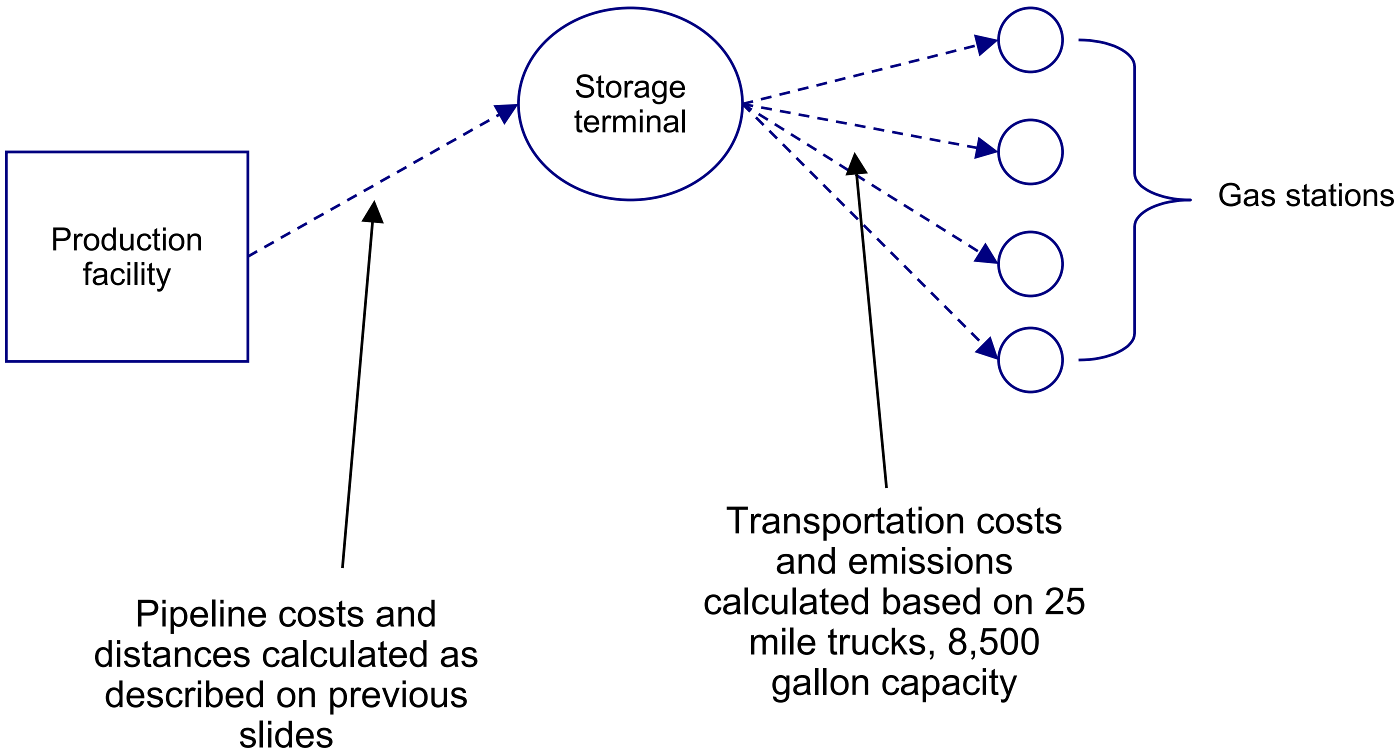
Source: True, Warren, "U.S. pipelines experience another tight year, reflect merger frenzy", *Oil and Gas Journal*, August 23, 1999. Actual costs (as opposed to projected costs shown), based on FERC filings from 6 distinct pipelines in Ohio, Indiana, Kansas and Alabama, ranging from 4 - 48 inch diameter pipes.

Fuel storage terminals will be required for some fuels...

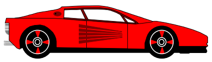
	Cost, $1,000	Source
Estimated total installed cost	**$2,208**	OPPA (get full reference from Ryan). Recent ADL studies have shown prices ranging from $5 - 25/bbl capacity in recent years.
Storage Capacity	100,000 bbl	
Equipment only costs	$1,699	
Throughput	1.5 loads/month	Estimated based on prior ADL work
Labor Costs per year	$100	Estimated
Annual maintenance (3% of equipment)	$51	Estimated
General overhead (65% of labor + maintenance)	$98	Estimated
Direct overhead (45% of labor + maintenance)	$45	Estimated
Total Operating costs, per facility per year	**$294**	

…but this contributes very little to the total fuel cost ($0.01/gallon for a 5 year payback on capital).

We have assumed that further transportation from a storage terminal requires 25 miles of transport in a diesel-fueled truck.



We have assumed that there are no marginal costs associated with gas stations, as these costs will exist independently.



Process Type	Fuel Distribution Network
Technology Type	

Fuel Type	Gasoline

Estimated Performance Characteristics	
Diesel use	0.0003 GJ diesel/ GJ gasoline
Electricity use	0.00004 GJ electric/ GJ gasoline
Heavy fuel oil use	0.00007 GJ fuel oil/ GJ gasoline

Key Assumptions

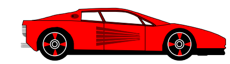
- Transport to bulk terminal is 62% by pipeline, 24% tanker and 14% barge
- Transport from bulk terminal to bulk station is by diesel truck
- Transport from bulk station to service station is by diesel truck

Other Inputs	
Electricity, Diesel, Heavy fuel oil	

Other Outputs	
Gasoline	

References (see References section for complete citation)

- Average fuel economy of all combination trucks as reported in Davis, Stacey, Transportation Energy Databook Edition 19, Oak Ridge National Laboratory, September 1999.
- "U.S. pipelines experience another tight year, reflect merger frenzy", Oil and Gas Journal, August 23, 1999, Table 7
- Deluchi, 1993 ANL/ESD/TM-22



Process Type	Pure EtOH Distribution	**Fuel Type**	EtOH
Technology Type			

Estimated Performance Characteristics	
Pipeline Distance (miles/1000 bbl/yr)	0.07
Capital Cost	$500,000/mi
Non-Fuel O&M Cost	2.8% of capital
Electricity Use	100 kJ/ton-mile

Key Assumptions

- Transport to bulk storage is by electric pipeline
- Transport from bulk storage is by diesel truck
- Cost of bulk storage facility is included
- Length of pipeline based on amount of fuel being produced
- Pipeline distance varies by region

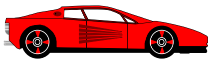
Other Inputs	
Electricity, Diesel	

Other Outputs	
Ethanol	

References (see References section for complete citation)

- Average fuel economy of all combination trucks as reported in Davis, Stacey, Transportation Energy Databook Edition 19, Oak Ridge National Laboratory, September 1999.
- "U.S. pipelines experience another tight year, reflect merger frenzy", Oil and Gas Journal, August 23, 1999, Table 7
- Deluchi, 1993 ANL/ESD/TM-22

Fuel Distribution FT Diesel



Process Type	FT Diesel Distribution Network
Technology Type	

Fuel Type	FT Diesel

Estimated Performance Characteristics	
Pipeline Distance (miles/1000 bbl/yr)	0.07
Capital	$500,000/mi
Non-Fuel O&M Cost	2.8% of capital
Electricity Use	100kJ/ton-mile

Key Assumptions

- Transport to bulk storage is by electric pipeline
- There is no capital cost of transport from bulk storage, as it can use existing diesel infrastructure
- Cost of bulk storage facility is not included, as it can use existing diesel infrastructure
- Length of pipeline based on amount of fuel being produced

Other Inputs	
Electricity, Diesel	

Other Outputs	
FT Diesel	

References (see References section for complete citation)

- Average fuel economy of all combination trucks as reported in Davis, Stacey, Transportation Energy Databook Edition 19, Oak Ridge National Laboratory, September 1999.
- "U.S. pipelines experience another tight year, reflect merger frenzy", Oil and Gas Journal, August 23, 1999, Table 7

Process Type	E10 Distribution Network
Technology Type	

Fuel Type	Blended Ethanol

Estimated Performance Characteristics	
Pipeline Distance (miles/1000 bbl/yr)	0.07
Capital	$500,000/mi
Non-Fuel O&M Cost	2.8% of capital
Electricity Use	100kJ/ton-mile

Key Assumptions

- Transport to bulk storage is by electric pipeline
- There is no capital cost of transport from bulk storage, as it can use existing gasoline infrastructure
- Cost of bulk storage facility is not included, as it can use existing gasoline infrastructure
- Length of pipeline based on amount of fuel being produced

Other Inputs	
Electricity, Diesel	

Other Outputs	
Blended Ethanol	

References (see References section for complete citation)

- "U.S. pipelines experience another tight year, reflect merger frenzy", Oil and Gas Journal, August 23, 1999, Table 7
- Average fuel economy of all combination trucks as reported in Davis, Stacey, Transportation Energy Databook Edition 19, Oak Ridge National Laboratory, September 1999.

Process Type	Fuel Marketing
Technology Type	

Fuel Type	Gasoline, Ethanol, Diesel, FT-Diesel

Key Assumptions

- There is no cost associated with fuel marketing
- Only emissions are evaporative emissions
- For blended ethanol, it will be blended at the distribution depot prior to shipment to the stations. This might result in additional investment cost which has not been addressed in this analysis

Tyson, Riley & Humphries, Fuel Cycle Evaluations of Biomass-Ethanol and Reformulated Gasoline, Volume I, National Renewable Energy Laboratory (NREL/TP-463-4950), Golden CO, November 1993.

References (see References section for complete citation)

The economics of specific examples within each of the selected bioproduct option categories were evaluated.

Low Temperature Processing	Low temperature processing employs an agent to break down the feedstock into its constituent parts (e.g. cellulose, hemicellulose, and lignin) which are then further processed. Example: Oil splitting of seed oils for fatty alcohol synthesis and glycerol recovery
Fermentation	Fermentation is being used by major chemical companies as a key technology platform to make monomers for performance polymers. Examples: lactic acid, 1,3-propanediol
Pyrolysis	Pyrolysis technology can convert a wide variety of biomass into a liquid oil. Products could then be recovered from that complex mixture. Examples: phenolics, sugars (levoglucosan) as a product or for further fermentation processing
C_1 Chemistry	C_1 chemistry via gasification and reforming. The resulting syngas is then used as a “building block” to build chemical products. Example: Naphtha from Fischer-Tropsch synthesis chemistry. This option is worth analyzing as it is a natural co-product from the production of bio-FT-diesel fuel

These examples include some of the most potentially attractive bioproduct options.

Process Type	Pyrolysis

Feedstock Types	Poplar
Technology Type	Phenolics Production

Estimated Performance Characteristics

Feedstock	Tons Product per year	Efficiency (HHV)	Capital Cost $MM	Operating Cost $MM per year	Petr. Fuel $MM / yr	Co-products	
Poplar	83,000	65.9%	42	5.3	1.0	Char Low Btu Gas	23,000 dry tons 6,300 MMSCF

Assumptions

- Maintenance estimated as 3 percent of fixed capital investment
- General overhead estimated as 65 percent of sum of maintenance and direct labor; Direct overhead estimated as 35 percent of direct labor
- 91.3 percent operating factor
- Contingency 25% of fixed capital; Owners cost, fee, profit 10% of fixed capital; Working capital 10% of fixed capital

References (see References section for complete citation)

- Communications with Biocarbons, Inc.

Bioproducts Pyrolysis *Levoglucosan*

Process Type	Pyrolysis

Feedstock Types	Poplar, Switchgrass
Technology Type	Levoglucosan

Estimated Performance Characteristics

Feedstock	Tons Product per year	Efficiency (HHV)	Capital Cost $MM	Operating Cost $MM / year	Petr. Fuel $MM / yr	Co-products (dry tons)		Additional Inputs
Poplar	62,000	36.0%	62	8.3	6.7	Acetic acid Char Sugars	2,300 22,000 70,000	Diesel Electricity Natural gas
Switchgrass	50,000	55.6%	63	8.3	9.9	Acetic acid Char Sugars	2,000 58,000 135,000	Diesel Electricity Natural gas

Assumptions

- Maintenance estimated as 3 percent of fixed capital investment
- General overhead estimated as 65 percent of sum of maintenance and direct labor; Direct overhead estimated as 35 percent of direct labor
- 91.3 percent operating factor
- Contingency 25% of fixed capital; Owners cost, fee, profit 10% of fixed capital; Working capital 10% of fixed capital

References (see References section for complete citation)

- Data based on conversations with Biocarbons, Inc. And literature data on yield data

Process Type	Fermentation

Feedstock Types	Corn
Technology Type	Lactic acid

Estimated Performance Characteristics						
Feedstock	**Tons Product per year**	**Efficiency (HHV)**	**Capital Cost $MM**	**Petr. Fuel Cos $MM / yr**	**Operating Cost $MM per year**	**Additional Inputs**
Corn	120,000	30.5%	608	10	52.5	Diesel Electricity Natural gas

Assumptions

- Maintenance estimated as 3 percent of fixed capital investment
- General overhead estimated as 65 percent of sum of maintenance and direct labor; Direct overhead estimated as 35 percent of direct labor
- 91.3 percent operating factor
- Contingency 25% of fixed capital; Owners cost, fee, profit 10% of fixed capital; Working capital 10% of fixed capital
- Cost based on simulated staggered batch fermentation, represents high end of cost

References (see References section for complete citation)

- Additional information from Lynd et al. "Biocommodity engineering" in Biotechnol Prog. Vol 15 p 777-793, Hovendahl et al. "Factors affecting fermentative lactic acid production" in Enz. and Micro. Technol vol 26 p 87-107 2000
- R. Datta et al. ”Technological and economic potential of poly(lactic acid) and lactic acid derivatives" in FEMS Microbiology Rev. vol 16 p 221-231, 1995
- Kammann and Erb: Kalkulationssyteme fuer den Anlaganbau in der chem. Industrie, Chime: Bioprozesstechnik, Crueger: Biotechnologie, Handbuch der Biotechnology

Process Type	Fermentation

Feedstock Types	Corn
Technology Type	1,3 Propanediol

Estimated Performance Characteristics

Feedstock	Tons Product per year	Efficiency (HHV)	Capital Cost $MM	Operating Cost $MM per year	Petr. Fuel cost $MM / yr	Additional Inputs
Corn	10,000	25.3%	38	5.8	1.1	Diesel Electricity Natural gas

Assumptions

- Maintenance estimated as 3 percent of fixed capital investment
- General overhead estimated as 65 percent of sum of maintenance and direct labor; Direct overhead estimated as 35 percent of direct labor
- 91.3 percent operating factor
- Contingency 25% of fixed capital; Owners cost, fee, profit 10% of fixed capital; Working capital 10% of fixed capital
- Continuous bubble column fermentation technology

References (see References section for complete citation)

- Cost based on a conceptional study by Grothe: Konzeption und Wirtschaftlichkeit der Industritellen Glycerinvergaerung zu 1,3PD
- Additional information from Cameron et al. "Metabolic Engineering of PD-pathways" in Biotechnol Prog. Vol 14 p 116-125 1999

Process Type	Low temperature processing

Feedstock Types	Soybean oil
Technology Type	Fatty Alcohol

Estimated Performance Characteristics

Feedstock	Tons Product per year	Efficiency (HHV)	Capital Cost $MM	Operating Cost $MM / year	Petr. Fuel $MM / yr	Co-products		Additional Inputs
Soybean oil	40,000	73.6%	133	18	1.9	Glycerin/ glycerol	6,000 dry tons	Electricity Hydrogen Natural gas

Assumptions

- Maintenance estimated as 3 percent of fixed capital investment
- General overhead estimated as 65 percent of sum of maintenance and direct labor; Direct overhead estimated as 35 percent of direct labor
- 91.3 percent operating factor
- Contingency 25% of fixed capital; Owners cost, fee, profit 10% of fixed capital; Working capital 10% of fixed capital

References (see References section for complete citation)

- ADL Internal client study on oil splitting economics

Grid Power Baseline Definitions

Cost Summary

All new installed grid power capacity is compared to the levelized cost of a natural gas fired gas turbine combined cycle plant.

Natural gas using gas turbine combined cycle as baseline

	¢/kWh				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Natural Gas Production / Source	0.0	0.0	1.9	2.3	1.9-2.3
Natural Gas Transport	0.0	0.0	0.05	0.06	0.05-0.06
Processing / Conversion	1.1	0.22	0.0	0.0	1.3
Total	1.1	0.22	2.0	2.3	**3.3-3.6**

Range represents range of natural gas costs of $2.90/MSCF to $3.47/MSCF

The coal co-firing options are compared to an estimated base load wholesale cost of ¢2.7/kWh.

NOx credits were $2000/ton and SOx credits were $200/ton.

Emissions Summary

All new installed grid power capacity is compared to the emissions of a natural gas fired gas turbine combined cycle plant.

Natural gas using gas turbine combine cycle for baseline

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Natural Gas Production / Source	0.26	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas Transport	9.6	0.00	0.07	0.05	0.01	0.00	0.02
Processing / Conversion	361	0.00	0.10	0.03	0.01	0.02	0.07
Total	**371**	**0.00**	**0.18**	**0.08**	**0.01**	**0.02**	**0.09**

The coal co-firing options are compared to coal Rankine power plant. Natural gas co-firing is compared to the natural gas, gas turbine combined cycle plant.

Coal processed using Rankine cycle for baseline

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Coal Extraction / Source	6.3	0.011	0.03	2.5	0.01	0.00	0.01
Coal Transport	1.4	0.001	0.01	0.00	0.00	0.00	0.01
Processing / Conversion	1,046	6.0	3.6	0.01	0.02	1.1	0.13
Total	**1,054**	**6.0**	**3.65**	**2.55**	**0.04**	**1.10**	**0.14**

Grid Power From Landfill Gas Direct Combustion

This summary describes the components, costs and performance characteristics of a fuel chain that produces grid power from landfill gases.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Landfill gas	• Resource generated on-site • Landfill gas has zero cost
Biomass Transport	N/A	Power generated on-site
Processing / Conversion	• Gas Turbine, η=26% • Gas Turbine Combined Cycle, η=40% • Fuel Cell, η=40% • Internal Combustion Engine, η=35%	Detailed assumptions on processing are on the power module summary sheets
Distribution & Transmission	Electricity cost reflects transmission and distribution energy losses of 7.2% but not actual delivery costs.	

Cost Summary

Natural gas using gas turbine combined cycle as baseline

Landfill gas processed using gas turbine

	¢/kWh				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.0	0.0	0.0	0.70	0.0-0.70
Biomass Transport	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	2.2	0.86	0.0	0.0	3.0
Total	2.2	0.86	0.0	0.0	**3.0-3.7**

** Range represents range of landfill gas costs of $0 to $0.39/MSCF*

Landfill gas processed using gas turbine combined cycle

	¢/kWh				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.0	0.0	0.0	0.46	0.0-0.46
Biomass Transport	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	2.8	1.1	0.0	0.0	3.9
Total	2.8	1.1	0.0	0.0	**3.9-4.4**

** Range represents range of landfill gas costs of $0 to $0.39/MSCF*

Landfill gas processed using fuel cell

	¢/kWh				
	Capital	Non-fuel O&M	Fuel* Low	Fuel* High	Total
Biomass Production / Source	0.0	0.0	0.0	0.46	0.0-0.46
Biomass Transport	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	3.3	1.4	0.0	0.0	4.7
Total	3.3	1.4	0.0	0.0	**4.7-5.1**

** Landfill gas is considered zero cost*

Landfill gas processed using internal combustion engine

	¢/kWh				
	Capital	Non-fuel O&M	Fuel* Low	Fuel* High	Total
Biomass Production / Source	0.0	0.0	0.0	0.52	0.0-0.52
Biomass Transport	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	2.4	1.4	0.0	0.0	3.8
Total	2.4	1.4	0.0	0.0	**3.8-4.3**

**Landfill gas is considered zero cost*

Emissions Summary

Natural gas using gas turbine combine cycle for baseline

Landfill gas processed using gas turbine

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	0.00	0.33	0.42	0.06	0.09	0.16	0.10
Total	**0.00**	**0.33**	**0.42**	**0.06**	**0.09**	**0.16**	**0.10**

Landfill gas processed using gas turbine combined cycle

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	0.00	0.21	0.27	0.04	0.06	0.11	0.07
Total	**0.00**	**0.21**	**0.27**	**0.04**	**0.06**	**0.11**	**0.07**

Landfill gas processed using fuel cell

	gm per kWh delivered						
	CO_2	SO_2	NOx	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Landfill gas processed using internal combustion engine

	gm per kWh delivered						
	CO_2	SO_2	NOx	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	0.00	0.24	1.6	6.6	1.2	0.16	1.6
Total	**0.00**	**0.24**	**1.6**	**6.6**	**1.2**	**0.16**	**1.6**

Grid Power from RDF Combustion and Gasification

This summary describes the components, costs and performance characteristics of a fuel chain that produces grid power from refuse derived fuels.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Refuse Derived Fuel	Resource generated on-site
Biomass Transport	N/A	Power is generated on-site
Processing / Conversion	• Direct combustion Rankine, η=27% • Gasification Rankine, η=27%	Detailed assumptions on processing are on the power module summary sheets
Distribution	Electricity cost reflects transmission and distribution energy losses of 7.2%, but not actual delivery costs.	

Cost Summary

Natural gas processed using gas turbine combined cycle as baseline

Refuse derived fuel processed using direct combustion Rankine

	¢/kWh				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.0	0.0	0.0	0.91	0.0-0.91
Biomass Transport	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	3.9	1.4	0.0	0.0	5.3
Total	3.9	1.4	0.0	0.91	**5.3-6.2**

** Range represents range of biomass feedstock costs of $0 to 10 per dry ton*

Refuse derived fuel processed using gasification Rankine

	¢/kWh				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.0	0.0	0.0	0.91	0.0-0.91
Biomass Transport	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	4.3	1.4	0.0	0.0	5.7
Total	4.3	1.4	0.0	0.91	**5.7-6.7**

** Range represents range of biomass feedstock costs of $0 to 10 per dry ton*

Emissions Summary

Natural gas using gas turbine combine cycle for baseline

Refuse derived fuel processed using direct combustion Rankine

	gm per kWh delivered						
	CO_2	SO_2	NOx	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	23	10	1.4	0.02	0.90	0.22	1.24
Total	**23**	**10**	**1.4**	**0.02**	**0.90**	**0.22**	**1.24**

Refuse derived fuel processed using gasification Rankine

	gm per kWh delivered						
	CO_2	SO_2	NOx	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	23	0.01	1.2	0.02	0.09	0.07	0.35
Total	**23**	**0.01**	**1.2**	**0.02**	**0.09**	**0.07**	**0.35**

Grid Power from Co-firing of Poplar/Wood

This summary describes the components, costs and performance characteristics of a fuel chain that produces grid power from poplar/wood by co-firing with coal or natural gas.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Poplar plantation	
Biomass Transport	50-mile truck	29 ton capacity truck, diesel fueled
Processing / Conversion	• Direct co-firing with coal, η=31% • Gasification co-firing with coal, η=26% • Gasification co-firing with natural gas, η=43%	• Detailed assumptions on processing are on the power module summary sheets • Co-firing at rate of 10 percent by heating value
Distribution	Electricity cost reflects transmission and distribution energy losses of 7.2%, but not actual delivery costs.	

Cost Summary

The coal co-firing options are compared to an estimated base load wholesale cost of ¢2.7/kWh.

Poplar processed using direct co-firing with coal

	¢/kWh					
	Capital	Non-fuel O&M	Fuel*		Emissions Credits	Total
			Low	High		
Biomass Production / Source	0.0	0.0	3.5	4.2	0.0	3.5-4.2
Biomass Transport	0.10	0.49	0.04	0.04	0.0	0.62
Processing / Conversion	0.35	0.51	0.05	0.05	-1.6	-0.72
Total	0.44	1.0	3.6	4.4	-1.6	**3.4-4.1**

Range represents range of biomass feedstock costs of $50 to 60 per dry ton

Poplar processed using gasification co-firing with coal

	¢/kWh					
	Capital	Non-fuel O&M	Fuel*		Emissions Credits	Total
			Low	High		
Biomass Production / Source	0.0	0.0	4.2	5.1	0.0	4.2-5.1
Biomass Transport	0.11	0.58	0.04	0.04	0.0	0.74
Processing / Conversion	1.3	0.60	0.06	0.06	-2.7	-0.71
Total	1.4	1.2	4.3	5.2	-2.7	**4.2-5.1**

** Range represents range of biomass feedstock costs of $50 to 60 per dry ton*

The gasification and then co-firing with natural gas option is compared to the levelized cost of a natural gas, gas turbine combined cycle plant.

Poplar processed using gasification co-firing with natural gas

	¢/kWh				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.0	0.0	2.6	3.1	2.6-3.1
Biomass Transport	0.07	0.35	0.03	0.03	0.46
Processing / Conversion	2.7	0.40	0.0	0.0	3.1
Total	2.8	0.75	2.6	3.1	**6.1-6.6**

** Range represents range of biomass feedstock costs of $50 to 60 per dry ton*

Emissions Summary

The coal co-firing options are compared to coal Rankine power plant.

Poplar processed using direct co-firing with coal

	gm per kWh delivered						
	CO_2	SO_2	NOx	CH_4	NMHC	PM	CO
Biomass Production / Source	45	0.14	0.16	0.00	0.02	0.01	0.06
Biomass Transport	8.1	0.00	0.06	0.00	0.01	0.00	0.01
Processing / Conversion	14	0.15	-3.8	0.01	0.02	0.21	0.14
Total	**67**	**0.29**	**-3.5**	**0.01**	**0.05**	**0.22**	**0.21**

Poplar processed using gasification co-firing with coal

	gm per kWh delivered						
	CO_2	SO_2	NOx	CH_4	NMHC	PM	CO
Biomass Production / Source	54	0.17	0.20	0.00	0.02	0.01	0.07
Biomass Transport	9.7	0.00	0.07	0.00	0.01	0.00	0.01
Processing / Conversion	17	0.17	-9.0	0.01	0.02	0.25	0.16
Total	**81**	**0.34**	**-8.8**	**0.01**	**0.06**	**0.26**	**0.24**

The gasification and co-firing with natural gas option is compared to a natural gas, gas turbine combined cycle plant.

Poplar processed using gasification co-firing with natural gas

	gm per kWh delivered						
	CO_2	SO_2	NOx	CH_4	NMHC	PM	CO
Biomass Production / Source	33	0.10	0.12	0.00	0.01	0.01	0.04
Biomass Transport	5.9	0.00	0.04	0.00	0.01	0.00	0.01
Processing / Conversion	10	0.10	0.24	0.04	0.02	0.03	0.11
Total	**49**	**0.20**	**0.41**	**0.04**	**0.04**	**0.04**	**0.16**

Grid Power from Co-firing of Switchgrass

This summary describes the components, costs and performance characteristics of a fuel chain that produces grid power from switchgrass by co-firing with coal or natural gas.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Switchgrass plantation	
Biomass Transport	50-mile truck	29 ton capacity truck, diesel fueled
Processing / Conversion	• Direct co-firing with coal, η=31% • Gasification co-firing with coal, η=26% • Gasification co-firing with natural gas, η=43%	• Detailed assumptions on processing are on the power module summary sheets • The co-firing is at a rate of 10 percent by heating value
Distribution	Electricity cost reflects transmission and distribution energy losses of 7.2%, but not actual delivery costs.	

Cost Summary

The coal co-firing options are compared to an estimated base load wholesale cost of ¢2.7/kWh.

Switchgrass processed using direct co-firing with coal

	¢/kWh					
	Capital	Non-fuel O&M	Fuel*		Emissions Credits	Total
			Low	High		
Biomass Production / Source	0.0	0.0	2.2	3.7	0.0	2.2-3.7
Biomass Transport	0.10	0.51	0.04	0.04	0.0	0.65
Processing / Conversion	0.35	0.51	0.05	0.05	-1.6	-0.71
Total	0.45	1.0	2.3	3.8	-0.15	**2.2-3.7**

Range represents range of biomass feedstock costs of $30 to 50 per dry ton

Switchgrass processed using gasification co-firing with coal

	¢/kWh					
	Capital	Non-fuel O&M	Fuel*		Emissions Credits	Total
			Low	High		
Biomass Production / Source	0.0	0.0	2.7	4.4	0.0	2.7-4.4
Biomass Transport	0.12	0.61	0.05	0.05	0.0	0.78
Processing / Conversion	1.3	0.60	0.06	0.06	-2.7	-0.69
Total	1.5	1.2	2.8	4.5	-2.7	**2.7-4.5**

** Range represents range of biomass feedstock costs of $30 to 50 per dry ton*

The gasification and then co-firing with natural gas option is compared to the levelized cost of a natural gas, gas turbine combined cycle plant.

Switchgrass processed using gasification co-firing with natural gas

	¢/kWh				
	Capital	Non-fuel O&M	Fuel* Low	Fuel* High	Total
Biomass Production / Source	0.0	0.0	1.6	2.7	1.6-2.7
Biomass Transport	0.07	0.37	0.03	0.03	0.47
Processing / Conversion	2.7	0.40	0.0	0.0	3.1
Total	2.8	0.77	1.6	2.7	**5.2-6.3**

** Range represents range of biomass feedstock costs of $30 to 50 per dry ton*

Emissions Summary

The coal co-firing options are compared to a coal Rankine power plant.

Switchgrass processed using direct co-firing with coal

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	45	0.14	0.16	0.00	0.02	0.01	0.06
Biomass Transport	8.5	0.00	0.06	0.00	0.01	0.00	0.01
Processing / Conversion	15	0.65	-3.8	0.01	0.02	0.79	0.14
Total	**69**	**0.79**	**-3.5**	**0.01**	**0.05**	**0.80**	**0.20**

Switchgrass processed using gasification co-firing with coal

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	54	0.16	0.20	0.00	0.02	0.01	0.07
Biomass Transport	10	0.00	0.08	0.00	0.01	0.00	0.01
Processing / Conversion	18	0.77	-9.0	0.01	0.02	0.94	0.16
Total	**82**	**0.94**	**-8.8**	**0.01**	**0.06**	**0.96**	**0.24**

The gasification and co-firing with natural gas option is compared to a natural gas, gas turbine combined cycle plant.

Switchgrass processed using gasification co-firing with natural gas

	gm per kWh delivered						
	CO_2	SO_2	NOx	CH_4	NMHC	PM	CO
Biomass Production / Source	33	0.10	0.12	0.00	0.01	0.01	0.04
Biomass Transport	6.2	0.00	0.05	0.00	0.01	0.00	0.01
Processing / Conversion	11	0.76	0.13	0.03	0.01	0.03	0.08
Total	**50**	**0.86**	**0.29**	**0.04**	**0.03**	**0.04**	**0.13**

Grid Power from Co-firing of Wheat straw

This summary describes the components, costs and performance characteristics of a fuel chain that produces grid power from wheat straw by co-firing with coal or natural gas.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Wheat straw plantation	Wheat and wheat straw are assigned emissions on an energy equivalent basis
Biomass Transport	50-mile truck	29 ton capacity truck, diesel fueled
Processing / Conversion	• Direct co-firing with coal, η=31% • Gasification co-firing with coal, η=26% • Gasification co-firing with natural gas, η=43%	• Detailed assumptions on processing are on the power module summary sheets • Co-firing at a rate of 10 percent by heating value
Distribution	Electricity cost reflects transmission and distribution energy losses of 7.2%, but not actual delivery costs.	

Cost Summary

The coal co-firing options are compared to an estimated base load wholesale cost of ¢2.7/kWh.

Wheat straw processed using direct co-firing with coal

	¢/kWh					
	Capital	Non-fuel O&M	Fuel*		Emissions Credits	Total
			Low	High		
Biomass Production / Source	0.0	0.0	2.3	3.9	0.0	2.3-3.9
Biomass Transport	0.11	0.54	0.04	0.04	0.0	0.69
Processing / Conversion	0.35	0.51	0.06	0.06	-1.6	-0.70
Total	0.45	1.0	2.4	4.0	-1.6	**2.3-3.9**

Range represents range of biomass feedstock costs of $30 to 50 per dry ton

Wheat straw processed using gasification co-firing with coal

	¢/kWh					
	Capital	Non-fuel O&M	Fuel*		Emissions Credits	Total
			Low	High		
Biomass Production / Source	0.0	0.0	2.8	4.7	0.0	2.8-4.7
Biomass Transport	0.13	0.64	0.05	0.05	0.0	0.82
Processing / Conversion	1.3	0.60	0.07	0.07	-2.7	-0.68
Total	1.5	1.2	2.9	4.8	-2.7	**2.9-4.8**

** Range represents range of biomass feedstock costs of $30 to 50 per dry ton*

The gasification and then co-firing with natural gas option is compared to the levelized cost of a natural gas, gas turbine combined cycle plant.

Wheat straw processed using gasification co-firing with natural gas

	¢/kWh				
	Capital	Non-fuel O&M	Fuel* Low	Fuel* High	Total
Biomass Production / Source	0.0	0.0	1.7	2.8	1.7-2.8
Biomass Transport	0.08	0.39	0.03	0.03	0.50
Processing / Conversion	2.7	0.40	0.0	0.0	3.1
Total	2.8	0.79	1.7	2.9	**5.3-6.4**

** Range represents range of biomass feedstock costs of $30 to 50 per dry ton*

Emissions Summary

The coal co-firing options are compared to a coal Rankine power plant.

Wheat straw processed using direct co-firing with coal

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	160	0.31	0.71	0.01	0.10	0.05	0.28
Biomass Transport	9.0	0.00	0.07	0.00	0.01	0.00	0.01
Processing / Conversion	16	0.96	-3.8	0.01	0.02	1.48	0.14
Total	**185**	**1.3**	**-3.0**	**0.02**	**0.13**	**1.53**	**0.43**

Wheat straw processed using gasification co-firing with coal

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	191	0.37	0.85	0.01	0.12	0.06	0.33
Biomass Transport	11	0.00	0.08	0.00	0.01	0.00	0.01
Processing / Conversion	19	1.14	-9.0	0.01	0.02	1.8	0.16
Total	**220**	**1.5**	**-8.1**	**0.02**	**0.15**	**1.8**	**0.51**

The gasification and co-firing with natural gas option is compared to a natural gas, gas turbine combined cycle plant.

Wheat straw processed using gasification co-firing with natural gas

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	116	0.23	0.51	0.01	0.07	0.04	0.20
Biomass Transport	6.5	0.00	0.05	0.00	0.01	0.00	0.01
Processing / Conversion	12	1.2	0.13	0.03	0.01	0.03	0.08
Total	**134**	**1.4**	**0.69**	**0.04**	**0.08**	**0.06**	**0.29**

Grid Power from Co-firing of Corn Stover

This summary describes the components, costs and performance characteristics of a fuel chain that produces grid power from corn stover by co-firing with coal or natural gas

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Corn farm with corn stover recovery	Corn and corn stover are assigned emissions on an energy equivalent basis
Biomass Transport	50-mile truck	29 ton capacity truck, diesel fueled
Processing / Conversion	• Direct co-firing with coal, η=31% • Gasification co-firing with coal, η=26% • Gasification co-firing with natural gas, η=43%	• Detailed assumptions on processing are on the power module summary sheets • Co-firing at a 10 percent rate based on heating value
Distribution	Electricity cost reflects transmission and distribution energy losses of 7.2%, but not actual delivery costs.	

Cost Summary

The coal co-firing options are compared to an estimated base load wholesale cost of ¢2.7/kWh.

Corn Stover processed using direct co-firing with coal

	¢/kWh					
	Capital	Non-fuel O&M	Fuel*		Emissions Credits	Total
			Low	High		
Biomass Production / Source	0.0	0.0	2.3	3.9	0.0	2.3-3.9
Biomass Transport	0.10	0.53	0.04	0.04	0.0	0.68
Processing / Conversion	0.35	0.51	0.05	0.05	-1.6	-0.71
Total	0.45	1.0	2.4	4.0	-1.6	**2.3-3.8**

Range represents range of biomass feedstock costs of $30 to 50 per dry ton

Corn stover processed using gasification co-firing with coal

	¢/kWh					
	Capital	Non-fuel O&M	Fuel*		Emissions Credits	Total
			Low	High		
Biomass Production / Source	0.0	0.0	2.8	4.6	0.0	2.8-4.6
Biomass Transport	0.12	0.64	0.05	0.05	0.0	0.81
Processing / Conversion	1.3	0.60	0.07	0.07	-2.7	-0.70
Total	1.5	1.2	2.9	4.7	-2.7	**2.9-4.7**

** Range represents range of biomass feedstock costs of $30 to 50 per dry ton*

The gasification and then co-firing with natural gas option is compared to the levelized cost of a natural gas, gas turbine combined cycle plant.

Corn stover processed using gasification co-firing with natural gas

	¢/kWh				
	Capital	Non-fuel O&M	Fuel* Low	Fuel* High	Total
Biomass Production / Source	0.0	0.0	1.7	2.8	1.7-2.8
Biomass Transport	0.08	0.39	0.03	0.03	0.49
Processing / Conversion	2.7	0.40	0.0	0.0	3.1
Total	2.8	0.79	1.7	2.9	**5.3-6.4**

** Range represents range of biomass feedstock costs of $30 to 50 per dry ton*

Emissions Summary

The coal co-firing options are compared to a coal Rankine power plant.

Corn stover processed using direct co-firing with coal

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	6.0	0.00	0.02	0.00	0.00	0.00	0.01
Biomass Transport	8.9	0.00	0.07	0.00	0.01	0.00	0.01
Processing / Conversion	15	0.16	-3.8	0.01	0.02	0.91	0.14
Total	**30**	**0.16**	**-3.7**	**0.01**	**0.03**	**0.91**	**0.16**

Corn stover processed using gasification co-firing with coal

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	7.1	0.00	0.03	0.00	0.00	0.00	0.01
Biomass Transport	11	0.00	0.08	0.00	0.01	0.00	0.01
Processing / Conversion	18	0.19	-9.0	0.01	0.02	1.09	0.16
Total	**36**	**0.20**	**-8.9**	**0.01**	**0.04**	**1.09**	**0.18**

The gasification and co-firing with natural gas option is compared to a natural gas, gas turbine combined cycle plant.

Corn stover processed using gasification co-firing with natural gas

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	4.3	0.00	0.02	0.00	0.00	0.00	0.01
Biomass Transport	6.4	0.00	0.05	0.00	0.01	0.00	0.01
Processing / Conversion	11	0.11	0.25	0.04	0.03	0.04	0.12
Total	**22**	**0.11**	**0.32**	**0.04**	**0.04**	**0.04**	**0.14**

Grid Power from Co-firing of Refuse Derived Fuels

This summary describes the components; costs and performance characteristics of a fuel chain that produces power from refuse derived fuels co-fired with coal and natural gas.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Refuse derived fuels	• Generated on-site
Biomass Transport	N/A	
Processing / Conversion	• Direct co-firing with coal, η=31% • Gasification co-firing with coal, η=26% • Gasification co-firing with natural gas, η=43%	• Detailed assumptions on processing are on the power module summary sheets • Co-firing is at a rate of 10 percent by heating value
Distribution	Electricity cost reflects transmission and distribution energy losses of 7.2%, but not actual delivery costs.	

Cost Summary

The coal co-firing options are compared to an estimated base load wholesale cost of ¢2.7/kWh.

Refuse derived fuels processed using direct co-firing with coal

	¢/kWh					
	Capital	Non-fuel O&M	Fuel*		Emissions Credits	Total
			Low	High		
Biomass Production / Source	0.0	0.0	0.0	0.79	0.0	0.0-0.79
Biomass Transport	0.0	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	0.35	0.51	0.06	0.09	-1.5	-0.61
Total	0.35	0.51	0.06	0.88	-1.5	**-0.61- +0.18**

Range represents range of biomass feedstock costs of $ 0 to 10 per dry ton

Refuse derived fuels processed using gasification co-firing with coal

	¢/kWh					
	Capital	Non-fuel O&M	Fuel*		Emissions Credits	Total
			Low	High		
Biomass Production / Source	0.0	0.0	0.0	0.94	0.0	0.0-0.94
Biomass Transport	0.0	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	1.3	0.60	0.07	0.07	-2.6	-0.58
Total	1.3	0.60	0.07	1.0	-2.6	**-0.58- +0.36**

Range represents range of biomass feedstock costs of $ 0 to 10 per dry ton

The gasification and then co-firing with natural gas option is compared to the levelized cost of a natural gas, gas turbine combined cycle plant.

Refuse derived fuels processed using gasification co-firing with natural gas

	¢/kWh				
	Capital	Non-fuel O&M	Fuel* Low	Fuel* High	Total
Biomass Production / Source	0.0	0.0	0.0	0.57	0.0-0.57
Biomass Transport	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	2.7	0.40	0.0	0.0	3.1
Total	2.7	0.40	0.0	0.57	**3.1-3.7**

Range represents range of biomass feedstock costs of $ 0 to 10 per dry ton

Emissions Summary

The coal co-firing options are compared to a coal Rankine power plant.

Refuse derived fuels processed using direct co-firing with coal

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	0.0	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.0	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	20	4.9	-3.8	0.01	0.02	0.01	0.14
Total	**20**	**4.9**	**-3.8**	**0.01**	**0.02**	**0.01**	**0.14**

Refuse derived fuels processed using gasification co-firing with coal

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	24	5.9	-9.0	0.01	0.02	0.02	0.16
Total	**24**	**5.9**	**-9.0**	**0.01**	**0.02**	**0.02**	**0.16**

The gasification and co-firing with natural gas option is compared to a natural gas, gas turbine combined cycle plant.

Refuse derived fuels processed using gasification co-firing with natural gas

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	15	6.4	0.26	0.04	0.03	0.04	0.12
Total	**15**	**6.4**	**0.26**	**0.04**	**0.03**	**0.04**	**0.12**

Grid Power from Co-firing of Sludge

This summary describes the components, costs and performance characteristics of a fuel chain that produces power from sludge by co-firing with coal.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Sludge	• Generated on-site
Biomass Transport	N/A	
Processing / Conversion	• Direct co-firing with coal, η=31% • Gasification co-firing with coal, η=26%	• Detailed assumptions on processing are on the power module summary sheets • Co-firing at a rate of 10 percent by heating value
Distribution	Electricity cost reflects transmission and distribution energy losses of 7.2%, but not actual delivery costs.	

Cost Summary

The coal co-firing options are compared to an estimated base load wholesale cost of ¢2.7/kWh.

Sludge processed using direct co-firing with coal

	¢/kWh					
	Capital	Non-fuel O&M	Fuel*		Emissions Credits	Total
			Low	High		
Biomass Production / Source	0.0	0.0	0.0	0.81	0.0	0.0-0.81
Biomass Transport	0.0	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	0.35	0.51	0.06	0.06	-1.2	-0.29
Total	0.35	0.51	0.06	0.86	-1.2	**-0.29-+0.52**

** Range represents range of biomass feedstock costs of $0 to 10 per dry ton*

Sludge processed using gasification co-firing with coal

	¢/kWh					
	Capital	Non-fuel O&M	Fuel*		Emissions Credits	Total
			Low	High		
Biomass Production / Source	0.0	0.0	0.0	0.96	0.0	0.0-0.96
Biomass Transport	0.0	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	1.3	0.60	0.07	0.07	-2.2	-0.20
Total	1.3	0.60	0.07	1.0	-2.2	**-0.20-+0.77**

** Range represents range of biomass feedstock costs of $0 to 10 per dry ton*

Emissions Summary

The coal co-firing options are compared to a coal Rankine power plant.

Sludge processed using direct co-firing with coal

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	11	21	-3.8	0.01	0.02	0.01	0.14
Total	**11**	**21**	**-3.8**	**0.01**	**0.02**	**0.01**	**0.14**

Sludge processed using gasification co-firing with coal

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	14	25	-9.0	0.01	0.02	0.02	0.16
Total	**14**	**25**	**-9.0**	**0.01**	**0.02**	**0.02**	**0.16**

Onsite Power Baseline Definitions

Cost Summary

All new installed onsite power capacity is compared to the average industrial power rate of ¢3.8/kWh. This rate is the 2010-projected price for the baseline case of the 2001 EIA Energy Outlook for the industrial sector. Distribution and transmission losses are not included since the power is used onsite.

Emissions Summary

All new installed onsite power capacity is compared to the national power mix. The emissions for the extraction and transport modules are calculated by a weighted average of the individual emissions from coal, natural gas, nuclear extraction and transport. Emissions from processing are average emissions from DOE/EIA Annual Energy Outlook 2000, EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 1998 (Draft), February 2000, and EPA National Air Pollutant Emissions Trends, 1900-1998, March 2000.

	Extraction	Transport	Processing
Coal	51.8%	51.8%	51.8%
Oil			2.4%
Gas	16.1%	16.1%	16.1%
Other			0.8%
Nuclear	18.4%	18.4%	18.4%
Other Non-Fossil			10.4%

National power mix

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Feedstock Production / Source	8	0.03	0.02	0.00	0.00	0.00	0.00
Feedstock Transport	2	0.00	0.01	0.01	0.00	0.00	0.00
Processing / Conversion	633	3.1	1.33	0.01	0.01	0.08	0.11
Total	**642**	**3.1**	**1.36**	**0.02**	**0.02**	**0.08**	**0.12**

All new installed onsite power capacity is compared to the national power mix. The natural gas combined cycle emissions are repeated for comparison.

Natural gas using gas turbine combine cycle for baseline

	gm per kWh delivered						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Natural Gas Production / Source	0.26	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas Transport	9.6	0.00	0.07	0.05	0.01	0.00	0.02
Processing / Conversion	361	0.00	0.10	0.03	0.01	0.02	0.07
Total	**371**	**0.00**	**0.18**	**0.08**	**0.01**	**0.02**	**0.09**

Onsite Power from Sewage Treatment Gas or Other Biogas Direct Combustion

This summary describes the components, costs and performance characteristics of a fuel chain that produces onsite power from sewage treatment gas or biogas (residue gas).

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Sewage gas Other Biogas	• Resource generated on-site • All biogas has zero cost
Biomass Transport	N/A	• Power generated on-site
Processing / Conversion	• Gas Turbine, η=26% • Gas Turbine Combined Cycle, η=40% • Fuel Cell, η=40% • Internal Combustion Engine, η=35%	• Detailed assumptions on processing are on the power module summary sheets
Distribution	N/A	

Cost Summary

All new installed onsite power capacity is compared to the average industrial power rate of ¢3.8/kWh. This rate is the 2010-projected price for the baseline case of the 2001 EIA Energy Outlook for the industrial sector.

Sewage treatment gas or other biogas processed using gas turbine

	¢/kWh				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.0	0.0	0.0	0.66	0.0-0.66
Biomass Transport	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	2.0	0.80	0.0	0.0	2.8
Total	2.0	0.80	0.0	0.43	**2.8-3.5**

** Range represents range of sewage and biogas costs of $0 to $0.39/MSCF*

Sewage treatment gas processed using gas turbine combined cycle

	¢/kWh				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.0	0.0	0.0	0.43	0.0-0.43
Biomass Transport	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	2.6	1.0	0.0	0.0	3.6
Total	2.6	1.0	0.0	0.43	**3.6-4.0**

** Range represents range of sewage and biogas costs of $0 to $0.39/MSCF*

Sewage treatment gas or other biogas processed using fuel cell

	¢/kWh				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.0	0.0	0.0	0.43	0.0-0.43
Biomass Transport	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	3.0	1.3	0.0	0.0	4.3
Total	3.0	1.3	0.0	0.43	**4.3-4.7**

** Range represents range of sewage and biogas costs of $0 to $0.39/MSCF*

Sewage treatment gas or other biogas processed using internal combustion engine

	¢/kWh				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.0	0.0	0.0	0.49	0.0-0.49
Biomass Transport	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	2.2	1.3	0.0	0.0	3.5
Total	2.2	1.3	0.0	0.49	**3.5-5.0**

** Range represents range of sewage and biogas costs of $0 to $0.39/MSCF*

Emissions Summary

All new installed onsite power capacity is compared to the national power mix.

Sewage treatment gas or other biogas processed using gas turbine

	gm per kWh generated						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	0.00	0.43	0.39	0.06	0.04	0.08	0.11
Total	**0.00**	**0.43**	**0.39**	**0.06**	**0.04**	**0.08**	**0.11**

Sewage treatment gas processed using gas turbine combined cycle

	gm per kWh generated						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	0.00	0.28	0.25	0.04	0.03	0.05	0.07
Total	**0.00**	**0.28**	**0.25**	**0.04**	**0.03**	**0.05**	**0.07**

Sewage treatment gas or other biogas processed using fuel cell

	gm per kWh generated						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Sewage treatment gas or other biogas processed using internal combustion engine

	gm per kWh generated						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	0.00	0.23	2.1	6.2	1.1	0.15	1.5
Total	**0.00**	**0.23**	**2.1**	**6.2**	**1.1**	**0.15**	**1.5**

Onsite Power from Gasification of Black Liquor

This summary describes the components, costs and performance characteristics of a fuel chain that produces onsite power from black liquor.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Black Liquor	Resource generated on-site
Biomass Transport	N/A	
Processing / Conversion	• Gas turbine combined cycle, η=21%	Detailed assumptions on processing are on the power module summary sheets
Distribution	N/A	

Cost Summary

All new installed onsite power capacity is compared to the average industrial power rate of ¢3.8/kWh. This rate is the 2010-projected price for the baseline case of the 2001 EIA Energy Outlook for the industrial sector.

Black liquor processed using gas turbine combined cycle

	¢/kWh				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.0	0.0	0.0	1.2	0.0-1.2
Biomass Transport	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	3.2	1.4	0.0	0.0	4.6
Total	3.2	1.4	0.0	1.2	**4.6-5.8**

** Range represents range of biomass feedstock costs of $0 to 10 per dry ton*

Emissions Summary

All new installed onsite power capacity is compared to the national power mix.

Black liquor processed using gas turbine combined cycle

	gm per kWh generated						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	25	0.03	1.1	0.02	0.10	0.07	0.25
Total	**25**	**0.03**	**1.1**	**0.02**	**0.10**	**0.07**	**0.25**

Onsite Power from Gasification of Solid Residues

This summary describes the components, costs and performance characteristics of a fuel chain that produces onsite power from solid residues.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Solid Residues	generated from other solid residues
Biomass Transport	N/A	
Processing / Conversion	• Gas turbine, η=26% • Gasification Rankine, η=27% • Internal combustion engine, η=31%	Detailed assumptions on processing are on the power module summary sheets
Distribution	N/A	

Cost Summary

All new installed onsite power capacity is compared to the average industrial power rate of ¢3.8/kWh. This rate is the 2010-projected price for the baseline case of the 2001 EIA Energy Outlook for the industrial sector.

Solid residues processed using gas turbine

	¢/kWh				
	Capital	Non-fuel O&M	Fuel		Total
			Low	High	
Biomass Production / Source	0.0	0.0	0.79	2.4	0.79-2.4
Biomass Transport	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	4.8	1.1	0.0	0.0	5.9
Total	4.8	1.1	0.79	2.4	**6.7-8.3**

** Range represents range of biomass feedstock costs of $10 to 30 per dry ton*

Solid residues processed using gasification Rankine

	¢/kWh				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.0	0.0	0.76	2.3	0.76-2.3
Biomass Transport	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	4.8	1.2	0.0	0.0	6.0
Total	4.8	1.2	0.76	2.3	**6.8-8.3**

Range represents range of biomass feedstock costs of $10 to 30 per dry ton

Solid residues processed using internal combustion engine

	¢/kWh				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.0	0.0	0.66	2.0	0.66-2.0
Biomass Transport	0.0	0.0	0.0	0.0	0.0
Processing / Conversion	3.2	1.3	0.0	0.0	4.5
Total	3.2	1.3	0.66	2.0	**5.2-6.5**

** Range represents range of biomass feedstock costs of $10 to 30 per dry ton*

Emissions Summary

All new installed onsite power capacity is compared to the national power mix.

Solid residues processed using gas turbine

	gm per kWh generated						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	16	0.06	1.0	0.02	0.08	0.06	0.20
Total	**16**	**0.06**	**1.0**	**0.02**	**0.08**	**0.06**	**0.20**

Solid residues processed using gasification Rankine

	gm per kWh generated						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	15	0.06	1.1	0.02	0.08	0.07	0.32
Total	**15**	**0.06**	**1.1**	**0.02**	**0.08**	**0.07**	**0.32**

Solid residues processed using internal combustion engine

	gm per kWh generated						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing / Conversion	13	0.05	2.5	1.9	1.2	0.07	1.7
Total	**13**	**0.05**	**2.5**	**1.9**	**1.2**	**0.07**	**1.7**

Fuel Baseline Definitions

Cost Summary

Gasoline: All pure ethanol fuels are compared to gasoline from petroleum. The baseline price of gasoline excluding state and federal taxes is $0.91 per gallon gasoline equivalent from the projected 2010 transportation sector average price for motor gasoline, EIA 2001 Annual Outlook (reference case).

Diesel: Fischer-Tropsch Diesel (FT-Diesel) fuel is compared to Diesel from petroleum. The baseline price of Diesel excluding state and federal taxes is $0.83 per gallon gasoline equivalent from the projected 2010 transportation sector average price for Diesel fuel (distillate), EIA 2001 Annual Outlook (reference case).

***Methyl tertiary butyl ether (MTBE)*:** Ethanol used as a blending agent for oxygenates for gasoline is compared to the price of MTBE. It is assumed that blending agents are valued by their octane value. The value or price of MTBE is taken from average 1998 through 2000 wholesale price data of regular unleaded gasoline (R+M/2 value of 87). Over the period of 1998 to 2000 the value of an octane barrel was $0.28 per octane per barrel (using an octane for MTBE of 109.5. The average premium price of MTBE over its octane value was 11 percent (compared to the Platts price for MTBE over the 1998-2000 timeframe. Using an average octane of 2010 gasoline of 89 and 2010 motor gasoline whole prices, the octane value of MTBE is $41.4 per barrel MTBE. With the 11 percent premium the value of MTBE is $46.0 per barrel. For ethanol (R+M)/2 value of 113, the octane value of ethanol is $42.4 per barrel. It is not clear that ethanol can achieve premium value because of its increase Reid vapor pressure. If an equivalent premium can be achieved of 11 percent, the value of ethanol would be $47.1 per barrel ethanol.

Distribution and marketing costs are estimated for each chain. Costs that are NOT included are any retrofit or new investment required for new /retrofitted fueling stations. Any necessary costs associated with vehicle retrofit are also NOT included.

Emissions Summary

All pure ethanol fuels are compared to gasoline from petroleum.

Gasoline from Petroleum, gm per mile driven

	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Petroleum Exploration & Production	11	0.02	0.02	0.02	0.01	0.00	0.01
Crude Oil Transport	3.0	0.02	0.01	0.00	0.01	0.00	0.01
Crude Oil Refining	37	0.03	0.04	0.00	0.04	0.00	0.04
Gasoline Distribution	3.3	0.01	0.01	0.00	0.00	0.00	0.00
Gasoline Marketing	0.0	0.00	0.00	0.00	0.06	0.00	0.00
Vehicle End Use	315	0.03	0.20	0.01	0.04	0.00	1.70
Total	**369**	**0.10**	**0.27**	**0.03**	**0.16**	**0.01**	**1.76**

Fischer-Tropsch Diesel and DME are compared to Diesel from petroleum.

Diesel from Petroleum, gm per mile driven

	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Petroleum Exploration & Production	11	0.02	0.02	0.02	0.01	0.00	0.01
Crude Oil Transport	2.9	0.02	0.01	0.00	0.01	0.00	0.01
Crude Oil Refining	8.3	0.01	0.01	0.00	0.03	0.00	0.02
Diesel Distribution	3.1	0.01	0.01	0.00	0.00	0.00	0.00
Diesel Marketing	0.0	0.00	0.00	0.00	0.00	0.00	0.00
Vehicle End Use	294	0.01	0.20	0.00	0.04	0.04	1.70
Total	**319**	**0.06**	**0.25**	**0.02**	**0.09**	**0.04**	**1.75**

Blended ethanol is compared with reformulated gasoline containing MTBE.

Reformulated gasoline (with MTBE) from Petroleum, gm per mile driven

	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Petroleum Exploration & Production	10	0.02	0.01	0.02	0.00	0.00	0.01
Crude Oil Transport	2.7	0.02	0.01	0.00	0.01	0.00	0.01
Crude Oil Refining	23.6	0.03	0.04	0.00	0.04	0.00	0.04
RFG Distribution	3.3	0.01	0.01	0.00	0.00	0.00	0.00
RFG Marketing	0.0	0.00	0.00	0.00	0.05	0.00	0.00
Vehicle End Use	299	0.03	0.20	0.01	0.04	0.00	1.70
Total	**339**	**0.10**	**0.27**	**0.03**	**0.15**	**0.00**	**1.76**

Vehicle Efficiencies

	Efficiency
Gasoline	15.7%
Diesel	16.9%
RFG	15.7%
Pure Ethanol	17.3%
FT Diesel	16.9%
Blended Ethanol	15.7%

Fuel Properties for Reference

	HHV of fuel, GJ per million gallons	Equivalent in terms of gallons of gasoline equivalent
Gasoline	129,072	1.0
Ethanol	88,590	0.686
FT Diesel	138,381	1.07

Fischer-Tropsch Diesel from Corn Stover

This summary describes the components, costs and performance characteristics of a fuel chain that produces Fischer-Tropsch (FT) diesel from corn stover. The costs are apportioned by product slate; 71.4% of the cost is apportioned to the FT diesel.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Corn stover plantation	• Corn farm with corn stover recovery • Corn and corn stover are assigned equivalent emissions on an energy basis
Biomass Transport	Corn stover truck	• 29 ton capacity truck, diesel fueled, travels 50 miles
Processing / Conversion	FT diesel from corn stover	• Based on syngas composition and product yield as given by Larson & Jin, 1999. • Costs adapted from a biomass methanol plant
Distribution	FT diesel distribution	• Pipeline from plant to bulk storage, 50 mile truck transport to marketing • Pipeline length varies with geographic region, according to population density
Marketing	FT diesel marketing	• Utilizes existing diesel distribution infrastructure
Vehicle End Use		• Emissions included for vehicle use.

Cost Summary

	$/gallon gasoline equivalent				
	Capital	Non-fuel O&M	Fuel* Low	Fuel* High	Total
Biomass Production / Source	0.00	0.00	0.50	0.84	0.50-0.84
Biomass Transport	0.02	0.12	0.01	0.01	0.15
Processing / Conversion	1.02	0.37	0.00	0.00	1.4
Distribution	0.13	0.06	0.00	0.00	0.19
Marketing	0.00	0.00	0.00	0.00	0.00
Total	1.2	0.55	0.51	0.85	**2.2-2.6**

** Range represents range of biomass feedstock costs of $30 to 50 per dry ton*

Emissions Summary

	gm/ mile driven						
	CO_2	SO_2	NOx	CH_4	NMHC	PM	CO
Biomass Production / Source	4.2	0.00	0.02	0.00	0.00	0.00	0.01
Biomass Transport	6.3	0.00	0.05	0.00	0.01	0.00	0.01
Processing / Conversion	0.00	0.00	0.05	0.00	0.01	0.00	0.01
Distribution	0.79	0.00	0.00	0.00	0.00	0.00	0.00
Marketing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Vehicle End Use	0.00	0.00	0.20	0.00	0.04	0.04	1.7
Total	**11**	**0.00**	**0.32**	**0.01**	**0.06**	**0.05**	**1.7**

** Emissions are split between naphtha and Diesel on an energy basis*

Fischer-Tropsch Diesel from Poplar

This summary describes the components, costs and performance characteristics of a fuel chain that produces Fischer-Tropsch (FT) diesel from poplar. The costs are apportioned by product slate; 71.6% of the cost is apportioned to the FT diesel.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Poplar plantation	• Short-rotation poplar plantation
Biomass Transport	Poplar truck	• 29 ton capacity truck, diesel fueled, travels 50 miles
Processing / Conversion	FT diesel from poplar	• Based on syngas composition and product yield as given by Larson & Jin, 1999. • Costs adapted from a biomass methanol plant
Distribution	FT diesel distribution	• Pipeline from plant to bulk storage, 50 mile truck transport to marketing • Pipeline length varies with geographic region, according to population density
Marketing	FT diesel marketing	• Utilizes existing diesel distribution infrastructure
Vehicle End Use		• Emissions included for vehicle use.

Cost Summary

	$/gallon gasoline equivalent				
	Capital	Non-fuel O&M	Fuel* Low	Fuel* High	Total
Biomass Production / Source	0.00	0.00	0.79	0.94	0.79-0.94
Biomass Transport	0.02	0.11	0.01	0.01	0.14
Processing / Conversion	0.96	0.35	0.00	0.00	1.3
Distribution	0.13	0.06	0.00	0.00	0.19
Marketing	0.00	0.00	0.00	0.00	0.00
Total	1.1	0.52	0.80	0.95	**2.4-2.6**

** Range represents range of biomass feedstock costs of $50 to 60 per dry ton*

Emissions Summary

	gm/ mile driven						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	33	0.10	0.12	0.00	0.01	0.01	0.04
Biomass Transport	5.9	0.00	0.04	0.00	0.01	0.00	0.01
Processing / Conversion	0.00	0.00	0.05	0.00	0.01	0.00	0.01
Distribution	0.79	0.00	0.00	0.00	0.00	0.00	0.00
Marketing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Vehicle End Use	0.00	0.00	0.20	0.00	0.04	0.04	1.7
Total	**39**	**0.10**	**0.41**	**0.01**	**0.07**	**0.05**	**1.8**

** Emissions are split between naphtha and Diesel on an energy basis*

Fischer-Tropsch Diesel from Switchgrass

This summary describes the components, costs and performance characteristics of a fuel chain that produces Fischer-Tropsch (FT) diesel from switchgrass. The costs are apportioned by product slate; 71.5% of the cost is apportioned to the FT diesel.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Switchgrass plantation	
Biomass Transport	Switchgrass truck	• 29 ton capacity truck, diesel fueled, travels 50 miles
Processing / Conversion	FT diesel from switchgrass	• Based on syngas composition and product yield as given by Larson & Jin, 1999. • Costs adapted from a biomass methanol plant
Distribution	FT diesel distribution	• Pipeline from plant to bulk storage, 50 mile truck transport to marketing • Pipeline length varies with geographic region, according to population density
Marketing	FT diesel marketing	• Utilizes existing diesel distribution infrastructure
Vehicle End Use		• Emissions included for vehicle use.

Cost Summary

	$/gallon gasoline equivalent				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.00	0.00	0.49	0.81	0.49-0.81
Biomass Transport	0.02	0.11	0.01	0.01	0.14
Processing / Conversion	0.99	0.36	0.00	0.00	1.3
Distribution	0.13	0.06	0.00	0.00	0.19
Marketing	0.00	0.00	0.00	0.00	0.00
Total	1.1	0.53	0.50	0.82	**2.2-2.5**

** Range represents range of biomass feedstock costs of $30 to 50 per dry ton*

Emissions Summary

	gm/ mile driven						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	32	0.10	0.12	0.00	0.01	0.01	0.04
Biomass Transport	6.1	0.00	0.05	0.00	0.01	0.00	0.01
Processing / Conversion	0.00	0.00	0.05	0.00	0.01	0.00	0.01
Distribution	0.79	0.00	0.00	0.00	0.00	0.00	0.00
Marketing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Vehicle End Use	0.00	0.00	0.20	0.00	0.04	0.04	1.7
Total	**39**	**0.10**	**0.41**	**0.01**	**0.07**	**0.05**	**1.8**

** Emissions are split between naphtha and Diesel on an energy basis*

Fischer-Tropsch Diesel from Wheat Straw

This summary describes the components, costs and performance characteristics of a fuel chain that produces Fischer-Tropsch (FT) diesel from wheat straw. The costs are apportioned by product slate; 71.4% of the cost is apportioned to the FT diesel.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Wheat straw plantation	• Wheat farm with wheat straw recovery • Wheat and wheat straw are assigned equivalent emissions on an energy basis
Biomass Transport	Wheat straw truck	• 29 ton capacity truck, diesel fueled, travels 50 miles
Processing / Conversion	FT diesel from wheat straw	• Based on syngas composition and product yield as given by Larson & Jin, 1999. • Costs adapted from a biomass methanol plant
Distribution	FT diesel distribution	• Pipeline from plant to bulk storage, 50 mile truck transport to marketing • Pipeline length varies with geographic region, according to population density
Marketing	FT diesel marketing	• Utilizes existing diesel distribution infrastructure
Vehicle End Use		• Emissions included for vehicle use

Cost Summary

	$/gallon gasoline equivalent				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.00	0.00	0.51	0.85	0.51-0.85
Biomass Transport	0.02	0.12	0.01	0.01	0.15
Processing / Conversion	1.0	0.38	0.00	0.00	1.4
Distribution	0.13	0.06	0.00	0.00	0.19
Marketing	0.00	0.00	0.00	0.00	0.00
Total	1.2	0.55	0.52	0.86	**2.2-2.6**

** Range represents range of biomass feedstock costs of $30 to 50 per dry ton*

Emissions Summary

	gm/ mile driven						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	113	0.22	0.50	0.00	0.07	0.03	0.20
Biomass Transport	6.3	0.00	0.05	0.00	0.01	0.00	0.01
Processing / Conversion	0.00	0.00	0.05	0.00	0.01	0.00	0.01
Distribution	0.79	0.00	0.00	0.00	0.00	0.00	0.00
Marketing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Vehicle End Use	0.00	0.00	0.20	0.00	0.04	0.04	1.7
Total	**120**	**0.22**	**0.80**	**0.01**	**0.12**	**0.08**	**1.9**

** Emissions are split between naphtha and Diesel on an energy basis*

Neat Ethanol from Corn

This summary describes the components, costs and performance characteristics of a fuel chain that produces neat ethanol from corn. The costs are apportioned by product slate; 62.9% of the cost is apportioned to the ethanol.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Corn farm	
Biomass Transport	Corn truck	• 29 ton capacity truck, diesel fueled, travels 50 miles
Processing / Conversion	Corn ethanol plant	Ethanol distillery, wet milling process, from Marland & Turhollow 1991
Distribution	Pure ethanol distribution network	• Pipeline from plant to bulk storage, 50 mile truck transport to marketing • Pipeline length varies with geographic region, according to population density
Marketing	Neat ethanol marketing	• Utilizes existing gasoline distribution infrastructure
Vehicle End Use		• Emissions included for vehicle use. • Cost not included

Cost Summary

	$/gallon gasoline equivalent				
	Capital	Non-fuel O&M	Fuel* Low	Fuel* High	Total
Biomass Production / Source	0.000	0.000	1.005		1.005
Biomass Transport	0.011	0.057	0.004		0.072
Processing / Conversion	0.214	0.246	0.204		0.663
Distribution	0.222	0.091	0.004		0.317
Marketing	0.000	0.000	0.000		0.000
Total	0.447	0.394	1.217		**2.06**

** There is no range of biomass feedstock costs*

Emissions Summary

	gm/ mile driven						
	CO_2	SO_2	NOx	CH_4	NMHC	PM	CO
Biomass Production / Source	2.6	0.00	0.01	0.00	0.00	0.00	0.00
Biomass Transport	3.0	0.00	0.02	0.00	0.00	0.00	0.00
Processing / Conversion	14	0.08	0.05	0.01	0.01	0.01	0.08
Distribution	0.67	0.00	0.00	0.00	0.00	0.00	0.00
Marketing	0.00	0.00	0.00	0.00	0.02	0.00	0.00
Vehicle End Use	0.00	0.00	0.20	0.01	0.04	0.00	1.7
Total	**20**	**0.08**	**0.29**	**0.01**	**0.07**	**0.01**	**1.8**

** Emissions are split between corn products on an energy basis, with 62.9% attributed to Ethanol*

Ethanol from Corn Stover, NREL 2010 best of industry, neat fuel

This summary describes the components, costs and performance characteristics of a fuel chain that produces neat ethanol from corn stover via the NREL 2010, best of industry SSF process. The costs are apportioned by product slate; 100% of the cost is apportioned to the ethanol.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Corn farm with corn stover recovery	• Corn farm with corn stover recovery
Biomass Transport	Corn stover truck	• 29 ton capacity truck, diesel fueled, travels 50 miles
Processing / Conversion	NREL SSF Ethanol from corn stover plant, 2010 best of industry	• Modified from NREL design for poplar, adjusted for the different carbohydrate and lignin fractions of the feedstock.
Distribution	Neat ethanol distribution	• Pipeline from plant to bulk storage, 50 mile truck transport to marketing • Pipeline length varies with geographic region, according to population density
Marketing	Neat ethanol Marketing	• Assumed to use existing gasoline marketing infrastructure • Includes evaporative emissions from refueling
Vehicle End Use		• Emissions included for vehicle use. • Cost not included

Cost Summary

	$/gallon gasoline equivalent				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.00	0.00	0.58	0.97	0.58-0.97
Biomass Transport	0.03	0.13	0.01	0.01	0.17
Processing / Conversion	0.55	0.39	0.01	0.01	0.96
Distribution	0.22	0.09	0.00	0.00	0.32
Marketing	0.00	0.00	0.00	0.00	0.00
Total	0.80	0.62	0.61	1.0	**2.0-2.4**

Range represents range of biomass feedstock costs of $30 to 50 per dry ton

Emissions Summary

	gm/ mile driven						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	4.8	0.00	0.02	0.00	0.00	0.00	0.01
Biomass Transport	7.2	0.00	0.05	0.00	0.01	0.00	0.01
Processing / Conversion	8.9	0.21	0.14	0.02	0.03	0.01	0.08
Distribution	0.67	0.00	0.00	0.00	0.00	0.00	0.00
Marketing	0.00	0.00	0.00	0.00	0.02	0.00	0.00
Vehicle End Use	0.00	0.00	0.20	0.01	0.04	0.00	1.7
Total	**22**	**0.22**	**0.42**	**0.03**	**0.10**	**0.01**	**1.8**

Ethanol from Poplar, NREL 2010 best of industry, neat fuel

This summary describes the components, costs and performance characteristics of a fuel chain that produces neat ethanol from poplar via the NREL 2010 SSF, best of industry process. The costs are apportioned by product slate; 95.1% of the cost is apportioned to the ethanol.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Poplar plantation	• Short-rotation poplar plantation
Biomass Transport	Poplar truck	• 29 ton capacity truck, diesel fueled, travels 50 miles
Processing / Conversion	NREL SSF Ethanol from Poplar plant, 2010 best of industry	• NREL 2010, best of industry SSF ethanol plant design
Distribution	Neat ethanol distribution	• Pipeline from plant to bulk storage, 50 mile truck transport to marketing • Pipeline length varies with geographic region, according to population density
Marketing	Neat ethanol Marketing	• Assumed to use existing gasoline marketing infrastructure • Includes evaporative emissions from refueling
Vehicle End Use		• Emissions included for vehicle use. • Cost not included

Cost Summary

	$/gallon gasoline equivalent				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.00	0.00	0.74	0.89	0.74-0.89
Biomass Transport	0.02	0.10	0.01	0.01	0.13
Processing / Conversion	0.42	0.31	0.01	0.01	0.74
Distribution	0.22	0.09	0.00	0.00	0.32
Marketing	0.00	0.00	0.00	0.00	0.00
Total	0.67	0.50	0.76	0.91	**1.9-2.1**

** Range represents range of biomass feedstock costs of $50 to 60 per dry ton*

Emissions Summary

	gm/ mile driven						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	30	0.09	0.11	0.00	0.01	0.01	0.04
Biomass Transport	5.5	0.00	0.04	0.00	0.01	0.00	0.01
Processing / Conversion	6.1	0.23	0.13	0.02	0.03	0.00	0.08
Distribution	0.67	0.00	0.00	0.00	0.00	0.00	0.00
Marketing	0.00	0.00	0.00	0.00	0.02	0.00	0.00
Vehicle End Use	0.00	0.00	0.20	0.01	0.04	0.00	1.7
Total	**43**	**0.32**	**0.48**	**0.03**	**0.11**	**0.01**	**1.8**

** Emissions are split between ethanol and electricity on an energy basis, with 95.1% attributed to ethanol*

Ethanol from Switchgrass, NREL 2010 best of industry, neat fuel

This summary describes the components, costs and performance characteristics of a fuel chain that produces neat ethanol from switchgrass via the NREL SSF 2010, best of industry process. The costs are apportioned by product slate; 100% of the cost is apportioned to the ethanol.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Switchgrass plantation	
Biomass Transport	Switchgrass truck	• 29 ton capacity truck, diesel fueled, travels 50 miles
Processing / Conversion	NREL SSF Ethanol from switchgrass plant, 2010 best of industry	• Modified from NREL design for poplar, adjusted for the different carbohydrate and lignin fractions of the feedstock.
Distribution	Neat ethanol distribution	• Pipeline from plant to bulk storage, 50 mile truck transport to marketing • Pipeline length varies with geographic region, according to population density
Marketing	Neat ethanol Marketing	• Assumed to use existing gasoline marketing infrastructure • Includes evaporative emissions from refueling
Vehicle End Use		• Emissions included for vehicle use. • Cost not included

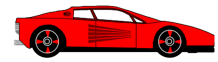
Cost Summary

	$/gallon gasoline equivalent				
	Capital	Non-fuel O&M	Fuel* Low	Fuel* High	Total
Biomass Production / Source	0.00	0.00	0.56	0.93	0.56-0.93
Biomass Transport	0.03	0.13	0.01	0.01	0.16
Processing / Conversion	0.45	0.32	0.01	0.01	0.79
Distribution	0.22	0.09	0.00	0.00	0.32
Marketing	0.00	0.00	0.00	0.00	0.00
Total	0.70	0.54	0.58	0.96	**1.8-2.2**

** Range represents range of biomass feedstock costs of $30 to 50 per dry ton*

Emissions Summary

	gm/ mile driven						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	36	0.11	0.13	0.00	0.01	0.01	0.05
Biomass Transport	6.8	0.00	0.05	0.00	0.01	0.00	0.01
Processing / Conversion	8.7	0.18	0.13	0.01	0.02	0.01	0.07
Distribution	0.67	0.00	0.00	0.00	0.00	0.00	0.00
Marketing	0.00	0.00	0.00	0.00	0.02	0.00	0.00
Vehicle End Use	0.00	0.00	0.20	0.01	0.04	0.00	1.7
Total	**52**	**0.29**	**0.51**	**0.02**	**0.11**	**0.02**	**1.8**



Ethanol from Wheat Straw, NREL 2010, best of industry, neat fuel

This summary describes the components, costs and performance characteristics of a fuel chain that produces neat ethanol from wheat straw via the NREL SSF 2010, best of industry process. The costs are apportioned by product slate; 97.9% of the cost is apportioned to the ethanol.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Wheat straw plantation	• Wheat farm with wheat straw recovery
Biomass Transport	Wheat straw truck	• 29 ton capacity truck, diesel fueled, travels 50 miles
Processing / Conversion	NREL SSF Ethanol from wheat straw plant, 2010 best of industry	• Modified from NREL design for poplar, adjusted for the different carbohydrate and lignin fractions of the feedstock.
Distribution	Neat ethanol distribution	• Pipeline from plant to bulk storage, 50 mile truck transport to marketing • Pipeline length varies with geographic region, according to population density
Marketing	Neat ethanol Marketing	• Assumed to use existing gasoline marketing infrastructure • Includes evaporative emissions from refueling
Vehicle End Use		• Emissions included for vehicle use. • Cost not included

Cost Summary

	$/gallon gasoline equivalent				
	Capital	**Non-fuel O&M**	**Fuel* Low**	**Fuel* High**	**Total**
Biomass Production / Source	0.00	0.00	0.50	0.84	0.50-0.84
Biomass Transport	0.02	0.12	0.01	0.01	0.15
Processing / Conversion	0.50	0.36	0.01	0.01	0.86
Distribution	0.22	0.09	0.00	0.00	0.32
Marketing	0.00	0.00	0.00	0.00	0.00
Total	0.74	0.56	0.53	0.86	**1.8-2.2**

** Range represents range of biomass feedstock costs of $30 to 50 per dry ton*

Emissions Summary

	gm/ mile driven						
	CO_2	**SO_2**	**NO_x**	**CH_4**	**NMHC**	**PM**	**CO**
Biomass Production / Source	110	0.22	0.49	0.00	0.07	0.03	0.19
Biomass Transport	6.2	0.00	0.05	0.00	0.01	0.00	0.01
Processing / Conversion	7.2	0.22	0.13	0.02	0.03	0.01	0.08
Distribution	0.67	0.00	0.00	0.00	0.00	0.00	0.00
Marketing	0.00	0.00	0.00	0.00	0.02	0.00	0.00
Vehicle End Use	0.00	0.00	0.20	0.01	0.04	0.00	1.7
Total	**124**	**0.44**	**0.87**	**0.03**	**0.16**	**0.04**	**2.0**

** Emissions are split between ethanol and electricity on an energy basis, with 97.9% attributed to ethanol*

2010 SSF Technology Blended Ethanol from Corn Stover

This summary describes the components; costs and performance characteristics of a fuel chain that produces blended ethanol from corn stover via the NREL 2010 best of industry process. The costs are apportioned by product slate; 100% of the cost is apportioned to the ethanol.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Corn stover plantation	• Corn farm with corn stover recovery
Biomass Transport	Corn stover truck	• 29 ton capacity truck, diesel fueled, travels 50 miles
Processing / Conversion	NREL Ethanol from corn stover , 2010 best of industry	• Modified from NREL design for poplar, adjusted for the different carbohydrate and lignin fractions of the feedstock.
Distribution	E10 distribution network	• Pipeline from plant to bulk storage, 50 mile truck transport to marketing • Pipeline length varies with geographic region, according to population density • Emissions and cost are only of ethanol portion
Marketing	E10 marketing	• Assumed to use existing gasoline marketing infrastructure • Includes evaporative emissions from refueling • Emissions and cost are only of ethanol portion
Vehicle End Use		• Emissions included for vehicle use. • Cost not included

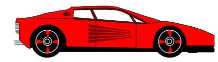
Cost Summary

	$/gallon				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.00	0.00	0.40	0.67	0.40-0.67
Biomass Transport	0.02	0.09	0.01	0.01	0.12
Processing / Conversion	0.38	0.27	0.01	0.01	0.66
Distribution	0.01	0.02	0.00	0.00	0.03
Marketing	0.00	0.00	0.00	0.00	0.00
Total	0.41	0.38	0.42	0.69	**1.2-1.5**

** Range represents range of biomass feedstock costs of $30 to 50 per dry ton*

Emissions Summary

	gm/ mile driven						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	5.3	0.00	0.02	0.00	0.00	0.00	0.01
Biomass Transport	7.9	0.00	0.06	0.00	0.01	0.00	0.01
Processing / Conversion	9.8	0.24	0.16	0.02	0.03	0.01	0.09
Distribution	1.7	0.00	0.01	0.00	0.00	0.00	0.00
Marketing	0.00	0.00	0.00	0.00	0.02	0.00	0.00
Vehicle End Use	0.00	0.00	0.20	0.01	0.04	0.00	1.7
Total	**25**	**0.24**	**0.44**	**0.03**	**0.11**	**0.01**	**1.8**



Ethanol from Poplar, NREL 2010 best of industry, blended fuel

This summary describes the components; costs and performance characteristics of a fuel chain that produces blended ethanol from poplar via the NREL 2010 best of industry process. The costs are apportioned by product slate; 95.1% of the cost is apportioned to the ethanol.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Poplar plantation	• Short-rotation poplar plantation
Biomass Transport	Poplar truck	• 29 ton capacity truck, diesel fueled, travels 50 miles
Processing / Conversion	NREL Ethanol from Poplar plant, 2010 best of industry	• NREL 2010, best of industry SSF ethanol plant design
Distribution	E10 distribution network	• Pipeline from plant to bulk storage, 50 mile truck transport to marketing • Pipeline length varies with geographic region, according to population density • Emissions and cost are only of ethanol portion
Marketing	E10 marketing	• Assumed to use existing gasoline marketing infrastructure • Includes evaporative emissions from refueling • Emissions and cost are only of ethanol portion
Vehicle End Use		• Emissions included for vehicle use. • Cost not included

Cost Summary

	$/gallon				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.00	0.00	0.51	0.61	0.51-0.61
Biomass Transport	0.01	0.07	0.01	0.01	0.09
Processing / Conversion	0.29	0.21	0.01	0.01	0.51
Distribution	0.01	0.02	0.00	0.00	0.03
Marketing	0.00	0.00	0.00	0.00	0.00
Total	0.32	0.30	0.52	0.62	**1.1-1.2**

** Range represents range of biomass feedstock costs of $50 to 60 per dry ton*

Emissions Summary

	gm/ mile driven						
	CO_2	SO_2	NOx	CH_4	NMHC	PM	CO
Biomass Production / Source	33	0.10	0.12	0.00	0.01	0.01	0.04
Biomass Transport	6.0	0.00	0.05	0.00	0.01	0.00	0.01
Processing / Conversion	6.7	0.25	0.14	0.02	0.03	0.01	0.09
Distribution	1.7	0.00	0.01	0.00	0.00	0.00	0.00
Marketing	0.00	0.00	0.00	0.00	0.02	0.00	0.00
Vehicle End Use	0.00	0.00	0.20	0.01	0.04	0.00	1.7
Total	**48**	**0.36**	**0.51**	**0.03**	**0.11**	**0.02**	**1.8**

** Emissions are split between ethanol and electricity on an energy basis, with 95.1% attributed to ethanol*

Ethanol from Switchgrass, NREL 2010 best of industry, blended fuel

This summary describes the components; costs and performance characteristics of a fuel chain that produces blended ethanol from switchgrass via the NREL 2010 best of industry process. The costs are apportioned by product slate; 100% of the cost is apportioned to the ethanol.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Switchgrass plantation	
Biomass Transport	Switchgrass truck	• 29 ton capacity truck, diesel fueled, travels 50 miles
Processing / Conversion	NREL Ethanol from switchgrass plant, 2010 best of industry	• modified from NREL design for poplar, adjusted for the different carbohydrate and lignin fractions of the feedstock
Distribution	E10 distribution network	• Pipeline from plant to bulk storage, 50 mile truck transport to marketing • Pipeline length varies with geographic region, according to population density • Emissions and cost are only of ethanol portion
Marketing	E10 marketing	• Assumed to use existing gasoline marketing infrastructure • Includes evaporative emissions from refueling • Emissions and cost are only of ethanol portion
Vehicle End Use		• Emissions included for vehicle use. • Cost not included

Cost Summary

	$/gallon				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.00	0.00	0.38	0.64	0.38-0.64
Biomass Transport	0.02	0.09	0.01	0.01	0.11
Processing / Conversion	0.31	0.22	0.01	0.01	0.54
Distribution	0.01	0.02	0.00	0.00	0.03
Marketing	0.00	0.00	0.00	0.00	0.00
Total	0.34	0.33	0.40	0.66	**1.1-1.3**

** Range represents range of biomass feedstock costs of $30 to 50 per dry ton*

Emissions Summary

	gm/ mile driven						
	CO_2	SO_2	NOx	CH_4	NMHC	PM	CO
Biomass Production / Source	40	0.12	0.14	0.00	0.02	0.01	0.05
Biomass Transport	7.5	0.00	0.06	0.00	0.01	0.00	0.01
Processing / Conversion	9.6	0.20	0.14	0.02	0.03	0.01	0.07
Distribution	1.7	0.00	0.01	0.00	0.00	0.00	0.00
Marketing	0.00	0.00	0.00	0.00	0.02	0.00	0.00
Vehicle End Use	0.00	0.00	0.20	0.01	0.04	0.00	1.7
Total	**59**	**0.32**	**0.55**	**0.03**	**0.11**	**0.02**	**1.8**

Ethanol from Wheat Straw, NREL 2010 best of industry, blended fuel

This summary describes the components; costs and performance characteristics of a fuel chain that produces blended ethanol from wheat straw via the NREL 2010 best of industry process. The costs are apportioned by product slate; 97.9% of the cost is apportioned to the ethanol.

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Wheat straw plantation	• Wheat farm with wheat straw recovery
Biomass Transport	Wheat straw truck	• 29 ton capacity truck, diesel fueled, travels 50 miles
Processing / Conversion	NREL Ethanol from wheat straw plant, 2010 best of industry	• modified from NREL design for poplar, adjusted for the different carbohydrate and lignin fractions of the feedstock
Distribution	E10 distribution network	• Pipeline from plant to bulk storage, 50 mile truck transport to marketing • Pipeline length varies with geographic region, according to population density • Emissions and cost are only of ethanol portion
Marketing	E10 marketing	• Assumed to use existing gasoline marketing infrastructure • Includes evaporative emissions from refueling • Emissions and cost are only of ethanol portion
Vehicle End Use		• Emissions included for vehicle use. • Cost not included

Cost Summary

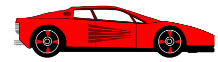
	$/gallon				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.00	0.00	0.35	0.58	0.35-0.58
Biomass Transport	0.02	0.08	0.01	0.01	0.10
Processing / Conversion	0.34	0.24	0.01	0.01	0.59
Distribution	0.01	0.02	0.00	0.00	0.03
Marketing	0.00	0.00	0.00	0.00	0.00
Total	0.37	0.34	0.36	0.59	**1.1-1.3**

** Range represents range of biomass feedstock costs of $30 to 50 per dry ton*

Emissions Summary

	gm/ mile driven						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	121	0.24	0.54	0.01	0.07	0.04	0.21
Biomass Transport	6.8	0.00	0.05	0.00	0.01	0.00	0.01
Processing / Conversion	8.0	0.24	0.15	0.02	0.03	0.01	0.09
Distribution	1.7	0.00	0.01	0.00	0.00	0.00	0.00
Marketing	0.00	0.00	0.00	0.00	0.02	0.00	0.00
Vehicle End Use	0.00	0.00	0.20	0.01	0.04	0.00	1.7
Total	**137**	**0.48**	**0.94**	**0.03**	**0.17**	**0.05**	**2.0**

** Emissions are split between ethanol and electricity on an energy basis, with 97.9% attributed to ethanol*



Blended Ethanol from Corn

This summary describes the components, costs and performance characteristics of a fuel chain that produces blended ethanol from corn. The costs are apportioned by product slate; 62.9% of the cost is apportioned to the ethanol

Fuel Chain Overview

	Module Name	Description
Biomass Production / Source	Corn farm	
Biomass Transport	Corn truck	• 29 ton capacity truck, diesel fueled, travels 50 miles
Processing / Conversion	Corn ethanol plant	• Ethanol distillery, dry milling process, from Marland & Turhollow 1991
Distribution	E10 distribution network	• Pipeline from plant to bulk storage, 50 mile truck transport to marketing • Pipeline length varies with geographic region, according to population density • Emissions and cost are only of ethanol portion
Marketing	E10 marketing	• Assumed to use existing gasoline marketing infrastructure • Includes evaporative emissions from refueling • Emissions and cost are only of ethanol portion
Vehicle End Use		• Emissions included for vehicle use. • Cost not included

Cost Summary

	$/gallon				
	Capital	Non-fuel O&M	Fuel*		Total
			Low	High	
Biomass Production / Source	0.00	0.00	0.69		0.69
Biomass Transport	0.01	0.04	0.00		0.05
Processing / Conversion	0.15	0.17	0.14		0.46
Distribution	0.01	0.02	0.00		0.03
Marketing	0.00	0.00	0.00		0.00
Total	0.17	0.23	0.83		**1.2**

** There is no range of biomass feedstock costs*

Emissions Summary

	gm/ mile driven						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	2.8	0.00	0.01	0.00	0.00	0.00	0.00
Biomass Transport	3.4	0.00	0.03	0.00	0.00	0.00	0.00
Processing / Conversion	15	0.09	0.06	0.01	0.01	0.01	0.08
Distribution	1.7	0.00	0.01	0.00	0.00	0.00	0.00
Marketing	0.00	0.00	0.00	0.00	0.02	0.00	0.00
Vehicle End Use	0.00	0.00	0.20	0.01	0.04	0.00	1.70
Total	**23**	**0.09**	**0.30**	**0.01**	**0.08**	**0.01**	**1.8**

Phenolics Obtained from Woody Feedstocks

This summary describes the components, costs and performance characteristics of a product chain that produces phenolics from woody biomass feedstocks. The phenolics have application as wood adhesives. The lignin content of grasses and straws is about half of that for wood. For the production of adhesive raw materials, most of the material is produced from the feed lignin. Dropping the production of adhesive material by feeding straw or grass, and then relying on the relatively small amounts of by-products is not economic. Consequently, the pyrolysis process that produces adhesive phenolics should not be fed switch grass or wheat straw. One hundred percent of the cost is apportioned to the primary product.

Product Chain Overview

	Module Name	Description
Biomass Production / Source	Poplar plantation	
Biomass Transport	50-mile truck	29 ton capacity truck, diesel fueled
Processing / Conversion	• Fluidized bed pyrolysis process • Recovery of phenolics from pyrolysis oils • Char and low-BTU gas by-products	Detailed assumptions on processing are on product module summary sheets

Product Slate

	Tons per day	Market Value, cents per pound
Poplar Feedstock	180	2.5-3.0
Phenolics	44	20
Char	13	10
Low BTU gas	129	0.9

Cost Summary

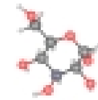
	Cents per pound, plant gate						
	By-product Credit	Capital	Non-fuel O&M	Fuel Cost	Feedstock		Totals
					Low	High	
Biomass	0	0.0	0.0	0.0	10	12	10-12
Biomass	0	0.27	1.4	0.11	0.0	0.0	1.8
Processing	-5.2	3.9	3.2	0.59	0.0	0.0	2.4
Total	**-5.2**	**4.1**	**4.6**	**0.70**	**10**	**12**	**14-16**

** Range represents range of biomass feedstock costs of $50 to 60 per dry ton*

Emissions Summary

	MT per 1000 tons, plant gate						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	121	0.37	0.44	0.01	0.05	0.03	0.15
Biomass Transport	21	0.01	0.16	0.00	0.02	0.01	0.02
Processing / Conversion	-879	0.43	0.43	0.03	0.04	0.02	0.19
Total	**-737**	**0.81**	**1.03**	**0.04**	**0.11**	**0.05**	**0.37**

All emissions of the plant are assigned to the phenolics product solely.



Levoglucosan and Other Sugars Obtained from Woody Feedstocks

This summary describes the components, costs and performance characteristics of a product chain that produces levoglucosan and other sugars from woody biomass feedstocks. A fluidized bed pyrolysis process is used to convert the biomass into an oil mixture from which the levoglucosan is recovered. One hundred percent of the cost is apportioned to the primary product.

Product Chain Overview

	Module Name	Description
Biomass Production / Source	Poplar plantation	
Biomass Transport	50-mile truck	29 ton capacity truck, diesel fueled
Processing / Conversion	• Fluidized bed pyrolysis process • Recovery of sugars from pyrolysis oils • Acetic acid, other sugars, Char by-products	Detailed assumptions on processing are on product module summary sheets

Product Slate

	Tons per day	Market Value, cents per pound
Poplar Feedstock	180	2.5-3.0
Levoglucosan	33	20
Char	12	10
Acetic acid	1.3	23
Sugars	38	18

Cost Summary

	Cents per pound, plant gate						
	By-product Credit	Capital	Non-fuel O&M	Fuel Cost	Feedstock Low	Feedstock High	Totals
Biomass Production / Source	0.0	0.0	0.0	0.0	13	16	13-16
Biomass Transport	0.0	0.36	1.8	0.14	0.0	0.0	2.3
Processing	-25	18	16	4.9	0.0	0.0	14
Total	**-25**	**81**	**18**	**5**	**13**	**16**	**29-32**

** Range represents range of biomass feedstock costs of $50 to 60 per dry ton*

Emissions Summary

	MT per 1000 tons phenolic						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	166	0.51	0.60	0.01	0.06	0.04	0.21
Biomass Transport	29	0.01	0.22	0.00	0.03	0.01	0.03
Processing / Conversion	-519	0.59	0.68	0.08	0.08	0.08	0.81
Total	**-324**	**1.10**	**1.50**	**0.09**	**0.18**	**0.13**	**1.05**

All emissions of the plant are assigned to the levoglucosan product solely.

Levoglucosan and Other Sugars Obtained from Grassy Feedstocks

This summary describes the components, costs and performance characteristics of a product chain that produces levoglucosan and other sugars from grassy (e.g. switchgrass or wheat straw) biomass feedstocks. A fluidized bed pyrolysis process is used to convert the biomass into an oil mixture from which the levoglucosan is recovered. One hundred percent of the cost is apportioned to the primary product.

Product Chain Overview

	Module Name	Description
Biomass Production / Source	Switchgrass plantation	
Biomass Transport	50-mile truck	29 ton capacity truck, diesel fueled
Processing / Conversion	• Fluidized bed pyrolysis process • Recovery of sugars from pyrolysis oils • Acetic acid, other sugars, Char by-products	Detailed assumptions on processing are on product module summary sheets

Product Slate

	Tons per day	Market Value, cents per pound
Switchgrass Feedstock	180	1.5-2.5
Levoglucosan	27	20
Char	33	10
Acetic acid	1.1	23
Sugars	74	18

Cost Summary

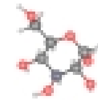
	Cents per pound, plant gate						
	By-product Credit	Capital	Non-fuel O&M	Fuel Cost	Feedstock Low	Feedstock High	Totals
Biomass Production / Source	0.0	0.0	0.0	0.0	10	17	10-17
Biomass Transport	0.0	0.45	2.3	0.18	0.0	0.0	3.0
Processing	-62	13	11	9.1	0.0	0.0	-29
Total	**-62**	**13**	**14**	**9**	**10**	**17**	**-16 to -9**

** Range represents range of biomass feedstock costs of $30 to 50 per dry ton*

Emissions Summary

	MT per 1000 tons, plant gate						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	107	0.33	0.39	0.00	0.04	0.03	0.14
Biomass Transport	20	0.01	0.15	0.00	0.02	0.01	0.02
Processing / Conversion	238	0.56	0.37	0.04	0.04	0.02	0.30
Total	**364**	**0.89**	**0.90**	**0.05**	**0.10**	**0.06**	**0.45**

All emissions of the plant are assigned to the levoglucosan product solely.



Lactic Acid from Corn Sugars

This summary describes the components; costs and performance characteristics of a product chain that produces lactic acid from glucose derived from corn. One hundred percent of the cost is apportioned to the primary product.

Product Chain Overview

	Module Name	Description
Biomass Production / Source	Corn Farm	
Biomass Transport	50-mile truck	29 ton capacity truck, diesel fueled
Processing / Conversion	Conversion of glucose derived from corn to lactic acid by fermentation processing	The cost for converting the corn into glucose is not included. The yield loss from converting corn into glucose is included. Detailed assumptions on processing are on product module summary sheets

Product Slate

	Tons per day	Market Value, cents per pound
Corn Feedstock	470	6.1
Lactic acid	330	79

Cost Summary

	Cents per pound, plant gate						
	By-product Credit	Capital	Non-fuel O&M	Fuel Cost	Feedstock Low	Feedstock High	Totals
Biomass Production / Source	0.0	0.0	0.0	0.0	8.7	8.7	8.7
Biomass Transport	0.0	0.10	0.49	0.04	0.0	0.0	0.63
Processing	0.0	39	22	4.2	0.0	0.0	65
Total	**0.0**	**39**	**22**	**4**	**8.7**	**8.7**	**75**

** There is no range of biomass feedstock costs, corn costs $2.92/dry bushel*

Emissions Summary

	MT per 1000 tons, plant gate						
	CO_2	SO_2	NOx	CH_4	NMHC	PM	CO
Biomass Production / Source	244	0.07	0.91	0.02	0.09	0.06	0.31
Biomass Transport	26	0.01	0.19	0.00	0.03	0.01	0.03
Processing / Conversion	49	3.87	1.94	0.05	0.05	0.11	0.36
Total	**319**	**3.96**	**3.04**	**0.07**	**0.17**	**0.17**	**0.70**

All emissions of the plant are assigned to the lactic acid product solely.

1,3-Propanediol from Corn Sugars

This summary describes the components; costs and performance characteristics of a product chain that produces 1,3-propanediol (1,3-propylene glycol) from glucose derived from corn. One hundred percent of the cost is apportioned to the primary product.

Product Chain Overview

	Module Name	Description
Biomass Production / Source	Corn Farm	
Biomass Transport	50-mile truck	29 ton capacity truck, diesel fueled
Processing / Conversion	• Conversion of glucose derived from corn to 1,3-propandiol by fermentation processing	The cost for converting the corn into glucose is not included. The yield loss from converting corn into glucose is included. Detailed assumptions on processing are on product module summary sheets

Product Slate

	Tons per day	Market Value, cents per pound
Corn Feedstock	82	6.1
1,3-Propanediol	28	20

Cost Summary

	Cents per pound, plant gate						
	By-product Credit	Capital	Non-fuel O&M	Fuel Cost	Feedstock		Totals
					Low	High	
Biomass Production	0.0	0.0	0.0	0.0	18	18	18
Biomass Transport	0.0	0.20	1.0	0.08	0.0	0.0	1.3
Processing	0.0	28	29	5.3	0.0	0.0	63
Total	**0.0**	**29**	**30**	**5.3**	**18**	**18**	**82**

** There is no range of biomass feedstock costs, corn costs $2.92/dry bushel*

Emissions Summary

	MT per 1000 tons, plant gate						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	471	0.14	1.75	0.03	0.18	0.11	0.60
Biomass Transport	49	0.02	0.37	0.00	0.05	0.02	0.05
Processing / Conversion	173	2.64	1.71	0.09	0.08	0.09	0.54
Total	**693**	**2.80**	**3.84**	**0.12**	**0.31**	**0.21**	**1.20**

All emissions of the plant are assigned to the 1,3-propanediol product solely.

Naphtha from Biomass

This summary describes the components, costs and performance characteristics of a product chain that produces naphtha from biomass. The biomass is gasified and then reformed to form a synthesis gas mixture ($CO+H_2$). The synthesis gas is then used to make Diesel and Naphtha via a Fischer-Tropsch synthesis and subsequent upgrading reactions.

Product Chain Overview

	Module Name	Description
Biomass Production / Source	Plantation	
Biomass Transport	50-mile truck	29 ton capacity truck, diesel fueled
Processing / Conversion	• Biomass gasification and reforming, Fischer-Tropsch synthesis, hydroisomerization upgrading	Detailed assumptions on processing are on product module summary sheets

Product Slate: Corn Stover

	Tons per day	Market Value, cents per pound
Biomass Feedstock	1,700	1.5-2.5
FT-Diesel	210	14
Naphtha	83	13

Product Slate: Switchgrass

	Tons per day	Market Value, cents per pound
Biomass Feedstock	1,700	1.5-2.5
FT-Diesel	220	14
Naphtha	86	13

Product Slate: Wheat Straw

	Tons per day	Market Value, cents per pound
Biomass Feedstock	1,700	1.5-2.5
FT-Diesel	210	14
Naphtha	82	13

Product Slate: Poplar

	Tons per day	Market Value, cents per pound
Biomass Feedstock	1,700	2.5-3.0
FT-Diesel	230	14
Naphtha	88	13

Cost Summary for Corn Stover

	Cents per pound, plant gate						
	By-product Credit	Capital	Non-fuel O&M	Fuel Cost	Feedstock Low	Feedstock High	Totals
Biomass Production / Source	0.0	0.0	0.0	0.0	8.5	14	8.5-14
Biomass Transport	0.0	0.38	1.9	0.15	0.0	0.0	2.5
Processing	0.0	20	7.2	0.0	0.0	0.0	27
Total	**0.0**	**20**	**9.1**	**0.15**	**8.5**	**14**	**38-43**

** Range represents range of biomass feedstock costs of $30-$50/dry ton. The capital, operating, fuel, and feedstock costs of the plant are apportioned between the diesel and naphtha products by a split based on heating value of product slate.*

Cost Summary for Switch grass

	Cents per pound, plant gate						
	By-product Credit	Capital	Non-fuel O&M	Fuel Cost	Feedstock Low	Feedstock High	Totals
Biomass Production	0.0	0.0	0.0	0.0	8.2	14	8.2-14
Biomass Transport	0.0	0.37	1.9	0.14	0.0	0.0	2.4
Processing	0.0	19	6.9	0.0	0.0	0.0	26
Total	**0.0**	**19**	**8.8**	**0.14**	**8.2**	**14**	**36-42**

** Range represents range of biomass feedstock costs of $30-$50/dry ton. The capital, operating, fuel, and feedstock costs of the plant are apportioned between the diesel and naphtha products by a split based on heating value of product slate.*

Cost Summary for Wheat Straw

	Cents per pound, plant gate						
	By-product Credit	Capital	Non-fuel O&M	Fuel Cost	Feedstock Low	Feedstock High	Totals
Biomass Production / Source	0.0	0.0	0.0	0.0	8.6	14	8.6-14
Biomass Transport	0.0	0.38	2.0	0.15	0.0	0.0	2.5
Processing	0.0	20	7.2	0.0	0.0	0.0	27
Total	**0.0**	**20**	**9.2**	**0.15**	**8.6**	**14**	**38-44**

** Range represents range of biomass feedstock costs of $30-$50/dry ton. The capital, operating, fuel, and feedstock costs of the plant are apportioned between the diesel and naphtha products by a split based on heating value of product slate.*

Cost Summary for Poplar

	Cents per pound, plant gate						
	By-product Credit	Capital	Non-fuel O&M	Fuel Cost	Feedstock Low	Feedstock High	Totals
Biomass Production / Source	0.0	0.0	0.0	0.0	13	16	13-16
Biomass Transport	0.0	0.36	1.8	0.14	0.0	0.0	2.3
Processing	0.0	18	6.7	0.0	0.0	0.0	25
Total	**0.0**	**19**	**8.5**	**0.14**	**13**	**16**	**41-43**

** Range represents range of biomass feedstock costs of $50-$60/dry ton. The capital, operating, fuel, and feedstock costs of the plant are apportioned between the diesel and naphtha products by a split based on heating value of product slate.*

Emissions Summary for Corn Stover

	MT per 1000 tons, plant gate						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	140	0.04	0.52	0.01	0.05	0.03	0.18
Biomass Transport	19	0.01	0.14	0.00	0.02	0.01	0.02
Processing / Conversion	0	0.00	0.20	0.02	0.03	0.02	0.04
Total	**159**	**0.05**	**0.86**	**0.03**	**0.10**	**0.06**	**0.24**

The emissions of the plant are apportioned between the diesel and naphtha products by split based on heating value of product slate.

Emissions Summary for Switchgrass

	MT per 1000 tons, plant gate						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	97	0.30	0.35	0.00	0.04	0.02	0.12
Biomass Transport	18	0.01	0.13	0.00	0.02	0.01	0.02
Processing / Conversion	0	0.00	0.19	0.02	0.03	0.02	0.04
Total	**115**	**0.30**	**0.68**	**0.02**	**0.08**	**0.05**	**0.18**

The emissions of the plant are apportioned between the diesel and naphtha products by split based on heating value of product slate.

Emissions Summary for Wheat Straw

	MT per 1000 tons, plant gate						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	347	0.68	1.5	0.02	0.21	0.11	0.61
Biomass Transport	19	0.01	0.14	0.00	0.02	0.01	0.02
Processing / Conversion	0	0.00	0.20	0.02	0.03	0.02	0.04
Total	**366**	**0.69**	**1.9**	**0.03**	**0.26**	**0.13**	**0.67**

The emissions of the plant are apportioned between the diesel and naphtha products by split based on heating value of product slate.

Emissions Summary for Poplar

	MT per 1000 tons, plant gate						
	CO_2	SO_2	NOx	CH_4	NMHC	PM	CO
Biomass Production / Source	100	0.30	0.36	0.00	0.04	0.02	0.13
Biomass Transport	17	0.01	0.13	0.00	0.02	0.01	0.02
Processing / Conversion	0	0.00	0.19	0.02	0.03	0.02	0.04
Total	**117**	**0.31**	**0.68**	**0.02**	**0.08**	**0.05**	**0.18**

The emissions of the plant are apportioned between the diesel and naphtha products by split based on heating value of product slate.

Fatty Alcohols from Seed Oils

This summary describes the components; costs and performance characteristics of a product chain that produces fatty alcohols from oil splitting process and subsequent hydrogenation of the split oils producing glycerin/glycerol as a co-product.

Product Chain Overview

	Module Name	Description
Biomass Production / Source	Seed Oil	
Biomass Transport	50-mile truck	29 ton capacity truck, diesel fueled
Processing / Conversion	• Oil splitting to produce fatty acid which is then upgraded to fatty alcohol and co-product glycerol	Detailed assumptions on processing are on product module summary sheets

Product Slate

	Tons per day	Market Value, cents per pound
Oil Feedstock	157	17
Fatty alcohol	110	96
Glycerol	17	30

Cost Summary

	Cents per pound, plant gate						
	By-product Credit	Capital	Non-fuel O&M	Fuel Cost	Feedstock Low	Feedstock High	Totals
Biomass Production / Source	*0.0*	0.0	0.0	0.0	25	25	25
Biomass Transport	0.0	2.4	6.7	0.49	0.0	0.0	10
Processing	-4.6	25	22	2.2	0.0	0.0	44
Total	**-4.6**	**27**	**29**	**2.7**	**25**	**25**	**79**

** There is no range of biomass feedstock costs*

Emissions Summary

	MT per 1000 tons, plant gate						
	CO_2	SO_2	NO_x	CH_4	NMHC	PM	CO
Biomass Production / Source	0	0.00	0.00	0.00	0.00	0.00	0.00
Biomass Transport	231	0.07	1.74	0.01	0.23	0.08	0.23
Processing / Conversion	159	0.55	0.24	0.00	0.00	0.01	0.04
Total	**390**	**0.62**	**1.98**	**0.02**	**0.24**	**0.09**	**0.27**

All emissions of the plant are assigned to the alcohol product solely.

Acronyms and Abbreviations

E1

- C&D = Construction and demolition
- DOE = Department of Energy (United States)
- dt = dry ton
- EIA = Energy Information Administration (United States)
- EPA = Environmental Protection Agency (United States)
- g/scf = grams per standard cubic feet
- lb/bu = pounds per bushel
- MSW = Municipal solid waste
- NREL = National Renewable Energy Laboratory (United States)
- ORNL = Oak Ridge National Laboratory (United States)
- U.S. = United States of America
- USDA = United States Department of Agriculture
- UTR = Urban tree residues

The majority of data used in the report comes from several key sources page 1 of 2:

Corn Stover Wheat Straw Rice Straw Cotton Stalks	• Walsh, Marie (ORNL). Personal communication (May 2000); and Walsh, M. E., et al. (2000). Biomass Feedstock Availability in the United States. Oak Ridge National Laboratory. Updated January 2000. Draft. • Rooney, T. N. C. (1998). Lignocellulosic feedstock resource assessment. Prepared for the National Renewable Energy Laboratory. • JACOR. March 1990. "Regional Assessment of Non Forestry-Related Biomass Resources: Summary Volume". Prepared for DOE, Southern RBEP. • Coates, W. E. (1996). "Harvesting systems for cotton plant residue." ASAE Applied Engineering in Agriculture **12**(6): 639-644. • USDA (2000). Agricultural Resources and Environmental Indicators 2000. U.S. Department of Agriculture, Resource Economics Division, Economic Research Service.
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Urban Tree Residues	• Fehrs, Jeffrey. December 1999. "Secondary Mill Residues and Urban Wood Waste Quantities in the United States". Prepared for DOE, Northeast RBEP. • Rooney, T. N. C. (1998). Lignocellulosic feedstock resource assessment. Prepared for the National Renewable Energy Laboratory. • NEOS Corporation (1994). Urban tree residues: Results of the first national inventory. Prepared for the International Society for Arboriculture Research Trust, Alleghany Power Service Corporation, National Arborist Foundation.
Primary Mill Residues	• Rooney, T. N. C. (1998). Lignocellulosic feedstock resource assessment. Prepared for the National Renewable Energy Laboratory. • USFS (1997). Forest Inventory and Analysis--Timber Product Output--Data Retrieval System. U.S. Forest Service. http://srsfia.usfs.msstate.edu/rpa/tpo.

Continued, page 2 of 2.

C&D Wood Organic MSW	• Fehrs, Jeffrey. December 1999. “Secondary Mill Residues and Urban Wood Waste Quantities in the United States”. Prepared for DOE, Northeast RBEP. • Walsh, Marie (ORNL). May 2000. Personal communication. • Franklin Associates (1999). Characterization of Municipal Solid Waste in the United States: 1998 Update. Prepared for the U.S. Environmental Protection Agency , EPA-530-R-98-007. • Glenn, J. (1998). “The State of Garbage in America.” BioCycle Journal of Composting & Recycling (April): 32-43.
Digester Gas Landfill Gas Sewage Gas	• U.S. EPA, Office of Policy. February 2000. “Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1998”. • U.S. EPA, Office of Air and Radiation. September 1999. “U.S. Methane Emissions 1990-2020: Inventories, Projections, and Opportunities for Reductions”. • Wirth, Tom (U.S. EPA, Climate Policy Team). Personal communication (June 2000); and U.S. EPA, Office of Air and Radiation. September 1999. “U.S. Methane Emissions 1990-2020: Inventories, Projections, and Opportunities for Reductions”. • U.S. EPA, Office of Water. December 1998. “Environmental Impacts of Animal Feeding Operations”. • EPA (1999A). Biosolids Generation, Use, and Disposal in the United States. U.S. Environmental Protection Agency, Municipal and Industrial Solid Waste Division, Office of Solid Waste. EPA530-R-99-009. • EPA website, “EPA Global Warming Site: National Emissions - Methane”, http://www.epa.gov/globalwarming/emissions/national/methane.html.
Manure Biosolids	• EPA (1998). Environmental Impacts of Animal Feeding Operations. Environmental Protection Agency, Office of Water Standards and Applied Sciences Division. • EPA (1999A). Biosolids Generation, Use, and Disposal in the United States. U.S. Environmental Protection Agency, Municipal and Industrial Solid Waste Division, Office of Solid Waste. EPA530-R-99-009.
Energy Crops	• Walsh, Marie (ORNL). Personal communication (May 2000); and Walsh, M. E., et al. (2000). Biomass Feedstock Availability in the United States. Oak Ridge National Laboratory. Updated January 2000. Draft.

Corn stover:

		Comments
Source Used	Marie Walsh (ORNL), personal communication	• Estimates state-level (county-level in some cases) collectable quantities and costs of collection • Costs are determined by the cost of collection plus a premium to the farmer • Assumes 45% collection on average to maintain soil quality (varies by state) • Excludes land with erodibility index of 8+ • Collectable quantities could be even lower if soil erosion factors are taken into account (this work is in progress)
Other Sources	JAYCOR, RBEP report	• Estimates state-level collectable quantities for the 13 Southeastern states • Assumes ~60% collection on average to account for collection difficulties, soil protection requirements, and maintenance of soil organic matter (varies by state) • Total quantity generated in the Southeast are much lower than Walsh data when collection fractions are applied (24 vs. 61 M dt/yr)
	Rooney - NEOS Corp, NREL report	• Estimates state-level collectable quantities and costs of collection • Costs are determined by the costs of collection which includes fixed costs, operating costs, and opportunity costs • Assumes 2 dry tons corn stover per acre are left in the field • Collectable quantity is much higher than Walsh data (236 vs. 123 M dt/yr) • Collectable quantity in the Southeast is much higher than JACOR data (21 vs. 14 M dt/yr) • The national average cost of collection is very close to Walsh data ($25/ton vs. $29/ton)

Winter wheat straw:

		Comments
Source Used	Marie Walsh (ORNL), personal communication	• Estimates state-level (county-level in some cases) collectable quantities and costs of collection • Costs are determined by the cost of collection plus a premium to the farmer • Assumes 17% collection on average to maintain soil quality (varies by state) • Excludes land with erodibility index of 8+ • Collectable quantities could be even lower if soil erosion factors are taken into account (this work is in progress)
Other Sources	JAYCOR, RBEP report	• Estimates state-level collectable quantities for the 13 Southeastern states • Assumes ~60% collection on average to account for collection difficulties, soil • protection requirements, and maintenance of soil organic matter (varies by state) • Total quantities generated in the Southeast are much lower than Walsh data when collection fractions are applied (12 vs. 36 M dt/yr)

Rice straw:

		Comments
Source Used	Rooney - NEOS Corp, NREL report	• Estimates state-level collectable quantities and costs of collection • Costs are determined by the costs of collection which includes fixed costs, operating costs, and opportunity costs • Assumes a national average of 35% collection for all states
Other Sources	JAYCOR, RBEP report	• Estimates state-level collectable quantities for the 13 Southeastern states (does not include California and Texas which are significant rice producing states) • Assumes all is collectable • Total quantities generated in the Southeast are slightly higher than NEOS data when collection fractions are applied (6.3 vs. 5.0 M dt/yr)

Forest residues:

		Comments
Source Used	Bob Perlack (ORNL), personal communications	• Estimates state-level supply curves based on collectable quantities and cost • Cost is a function of collection cost, stumpage fee, and transportation cost • Collectable quantities are determined based on site slope, accessibility, and retrieval efficiency
Other Sources	Antares Group Inc, NREL report	• Estimates state-level collectable quantities • Assumes 2.3 tons of residues are available per thousand cubic feet of harvested timber volume • Collectable quantity is equivalent Perlack data at \$30 - \$40/dry ton farm-gate

Primary mill residues:

		Comments
Source Used	U.S. Forest Service report	• Estimates state-level unused quantities (burned or landfilled) for hardwood and softwood by type (bark, coarse, and fine) based on Forest Service state surveys
	Rooney - NEOS Corp, NREL report	• Estimates prices paid for currently used residues • Prices based on EIA data which uses information obtained from timber dealers, foresters, utilities, sawmills, state energy offices, and trade associations • We assume that unused residue prices will be the same as those currently in use
Other Sources	Marie Walsh, personal communication	• Uses U.S. Forest Service data

Urban tree residues:

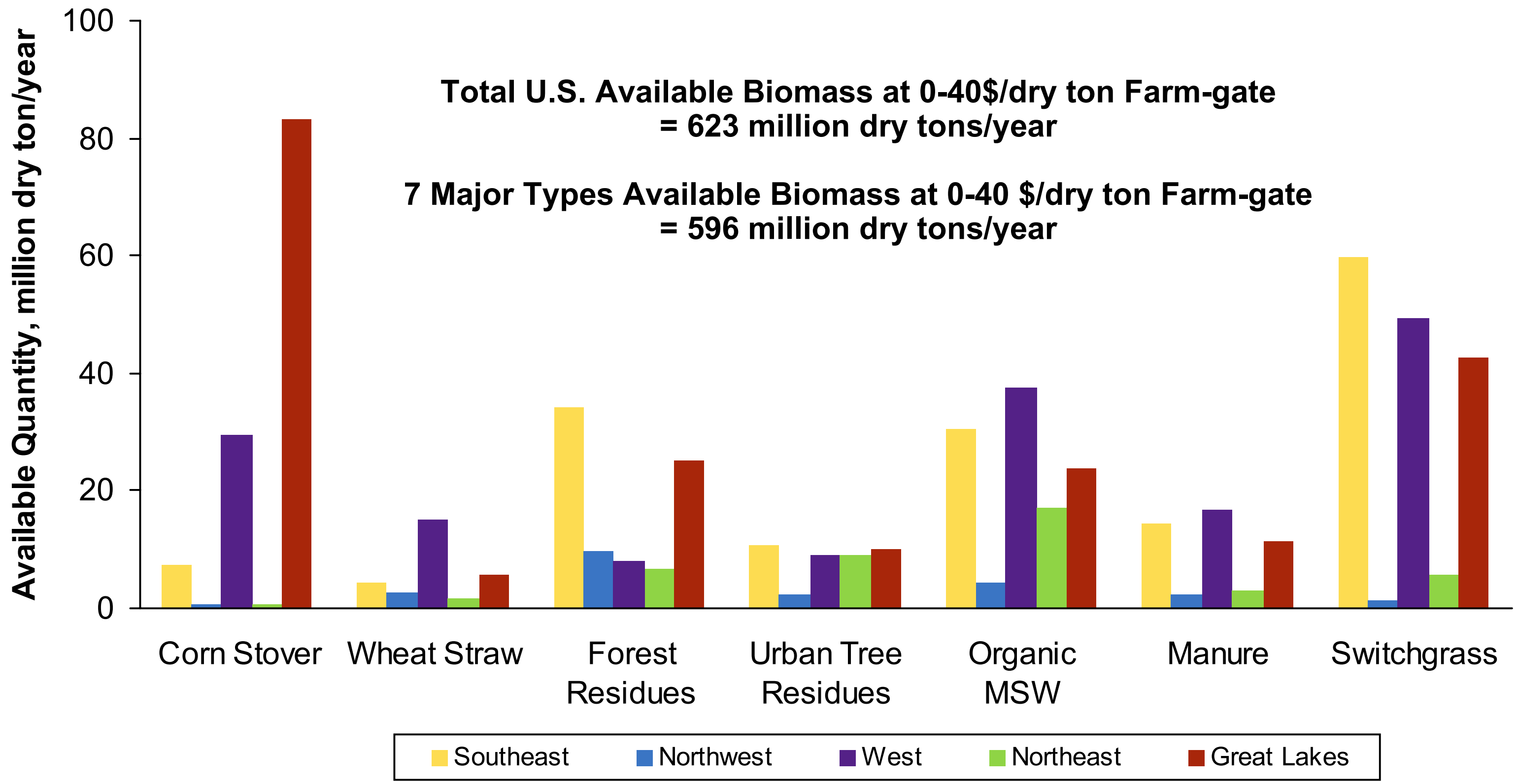
		Comments
Source Used	NEOS Corp, NREL report and National Arborist Foundation report	• Estimates state-level total generated quantities of UTR by type (chips, logs, tops/brush, etc.) based on a nation-wide mail and telephone survey of arboriculture and urban forest industries. • Estimates national fractions of available residues (incinerated, left on-site, open burned, or other use) by UTR type. • Estimates state-level tipping fees based on regional survey data.
Other Sources	Jeffery Fehrs, NERBEP report	• Uses NEOS Corp data

Construction and demolition wood:

		Comments
Source Used	Marie Walsh, personal communication	• Estimates state-level unused quantities based on the number of C/D landfills by state and average quantity of waste received per C/D landfill by region (Bush Pallet Enterprise article, and Glenn Biocycle article)
Other Sources	Jeffery Fehrs, NERBEP report	• It is not clear how national total C/D quantity was determined, but it is much higher than Walsh data (29 vs. 14 M dt/yr).

Seven biomass types make up 96% of available biomass in this analysis at 0-40 $/dry ton farm-gate.

Major Biomass Types
Regional Available Quantities at 0-40 $/dry ton Farm-gate



Data from regional available quantities are shown below:

Major Biomass Types
Regional Available Quantities at 0-40 $/dry ton Farm-gate

	Agricultural Crop Residues	Forest Residues	Primary Mill Residues	Other Wastes	Biogas	Sludge	Potential Energy Crops
Southeast	14.4	34.3	1.0	45.1	3.3	15.2	59.9
Northwest	3.2	9.7	0.1	7.2	0.4	2.4	1.3
West	47.0	8.1	0.2	47.8	3.6	17.4	49.4
Northeast	2.3	6.6	0.3	26.6	0.9	3.4	5.6
Great Lakes	89.1	25.1	0.2	34.6	3.2	12.1	42.5

Note: Regions defined by Regional Biomass Energy Program: Great Lakes region: MN, IA, WI, IL, IN, OH and MI; Northeast: New England, NY, PA, NJ, and DE; Northwest: WA, OR, ID, and MT; Southeast: MD, WV, VA, NC, SC, GA, FL, AL, MS, LA, AR, MO, KY, TN; West: CA, NV, WY, ND, SD, NE, KN, OK, TX, NM, CO, UT, AR; Data did not include Hawaii and Alaska

Source: Arthur D. Little analysis based on existing resource assessment studies

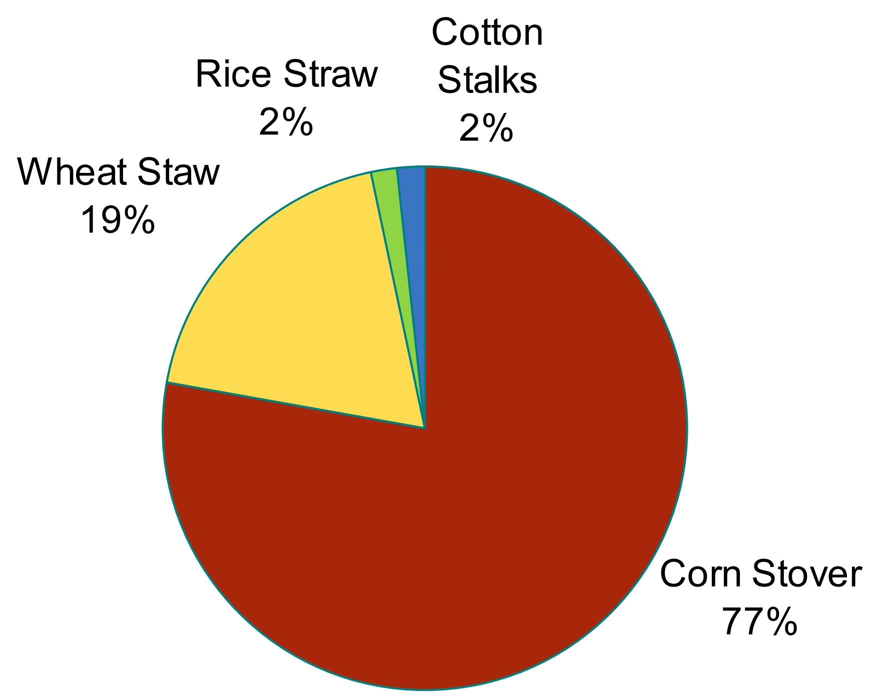
Data from overall supply curve shown below:

Major Biomass Types
Supply Curve Data (Farm-gate Price)

	Farm gate price, $/dry ton, transportation & processing not included										
in MM tons/year	0	10	20	30	40	50	60	70	80	90	100
Agricultural Crop Residue	0.0	0.0	3.2	138.8	155.9	157.5	157.6	157.9	158.0	158.0	158.0
Forest Residues	0.0	0.0	0.0	19.2	83.7	104.5	110.4	117.7	121.6	123.1	123.4
Primary Mill Residues	0.0	0.0	0.3	1.8							
Wastes	123.6	161.4									
Bio Gas	11.3										
Sludge	50.5										
Energy Crops	0.0	0.0	0.0	59.1	158.7	212.1					

The majority of agricultural crop residues are from corn stover and wheat straw, but other residues can have important local impacts.

U.S. Agricultural Crop Residue Fractions
Based on Available Quantities at 0-40 $/dry ton Farm-gate



Available Quantity at 0-40 $/dry ton Farm-gate = 156 million dry tons/year

Corn stover and wheat straw state-level quantity and price data is based on analyses by Oak Ridge National Laboratory[1].

- Estimated available quantities in 48 states
  - Uses USDA projected corn and wheat crop yields and acreage to obtain grain quantities
  - Assumes gain weights of 56 and 60 lb/bu, and grain moisture factors of 1 and 0.87 for corn and wheat, respectively
  - Assumes residue to grain ratios of 1:1 for corn stover, 1.7:1 for winter wheat straw, and 1.3:1 for spring and duram wheat straw
  - Collectable fraction based on need to maintain soil carbon
    - Quantities left in the field were determined by crop type, soil type, typical weather conditions, and the tillage system used
    - Usually 2 ton/acre left in the field for every 1-1.5 ton/acre collected (30-40% collection)
    - Collectable quantities could be even lower if soil erosion factors are taken into account (work in progress)
- Estimated price based on cost of collection, premium to the farmer, and transportation costs
  - Cost of collection estimates the cost of mowing (corn stover only), raking, baling, pickup, transport, and unloading of bales at the side of the field
    - Mowing is often eliminated and raking is sometimes eliminated when possible
  - Cost of collection is consistent with USDA methodology for agricultural crop production costs
  - $20/dt is assumed for the premium to the farmer and transportation cost
    - We have subtracted $10/dt for transportation costs to obtain farm-gate prices[2]

1. Walsh, M. E., et al. (2000). Biomass Feedstock Availability in the United States. Oak Ridge National Laboratory. Updated January 2000. Draft.
2. farm-gate price excludes delivery cost to the end use site.

Rice straw state-level quantity and price data is based on a report for NREL (Rooney, 1998).

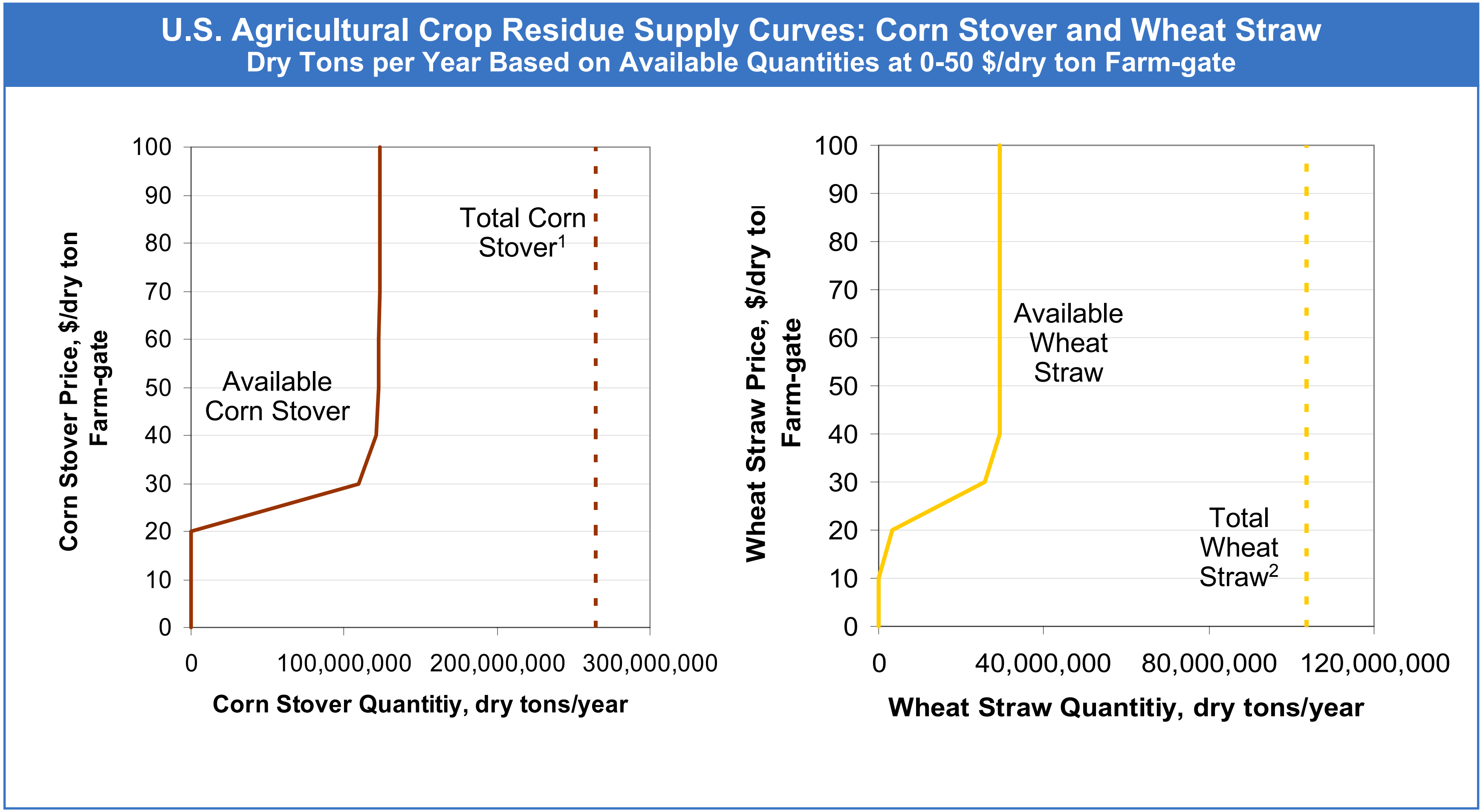
- Estimated available quantities in the 6 major rice producing states using USDA NASS crop acreage and yield data
  - Assumes a moisture content of 40% at the time of residue collection[1]
  - Assumes 65% of straw must be left in the field to maintain soil quality and prevent erosion
- Estimated price based on the cost of collection with the addition of a return for land, equipment, and soil nutrients
  - This price estimation follows the methodologies used by ORNL
  - Costs include:
    - Fixed costs - depreciation, interest, insurance, and housing for equipment;
    - Operating costs - equipment fuel, labor, repair, and maintenance costs;
    - Opportunity costs - net income forgone by choosing to use equipment for residue collection rather than other production activities, and estimates of the value of production value forgone by the removal of nutrients in residues
  - Costs do not include property taxes and depreciation of improvements

1. This level of moisture content would require weeks or months before collection. Rice straw moisture content at harvest is around 80%.

Cotton stalk state-level quantity and price data is based on a University of Arizona report[1].

- We estimated state-level available quantities using USDA cotton production data and an estimate from a University of Arizona report
  - An estimate in a University of Arizona report (Coates, 1996) indicates that 2.6 million tons per year cotton crop residues are produced in the U.S. (based on 11 million acres of cotton planted)
  - We used state-level cotton production from the USDA (USDA, 2000) to weigh the total residue quantity into state-level quantities
  - The actual available quantities by state will vary significantly based on the dominate production, harvesting, and tillage practices in the area
- We assumed that the price would be similar to other agricultural residue prices
  - We assume all cotton stalks can be obtained for $30/dry ton farm-gate
  - An economic assessment of cotton stalk harvesting in Arizona (Gomes et al, 1997) estimated the price for delivered residues of between 18-45 $/dry ton

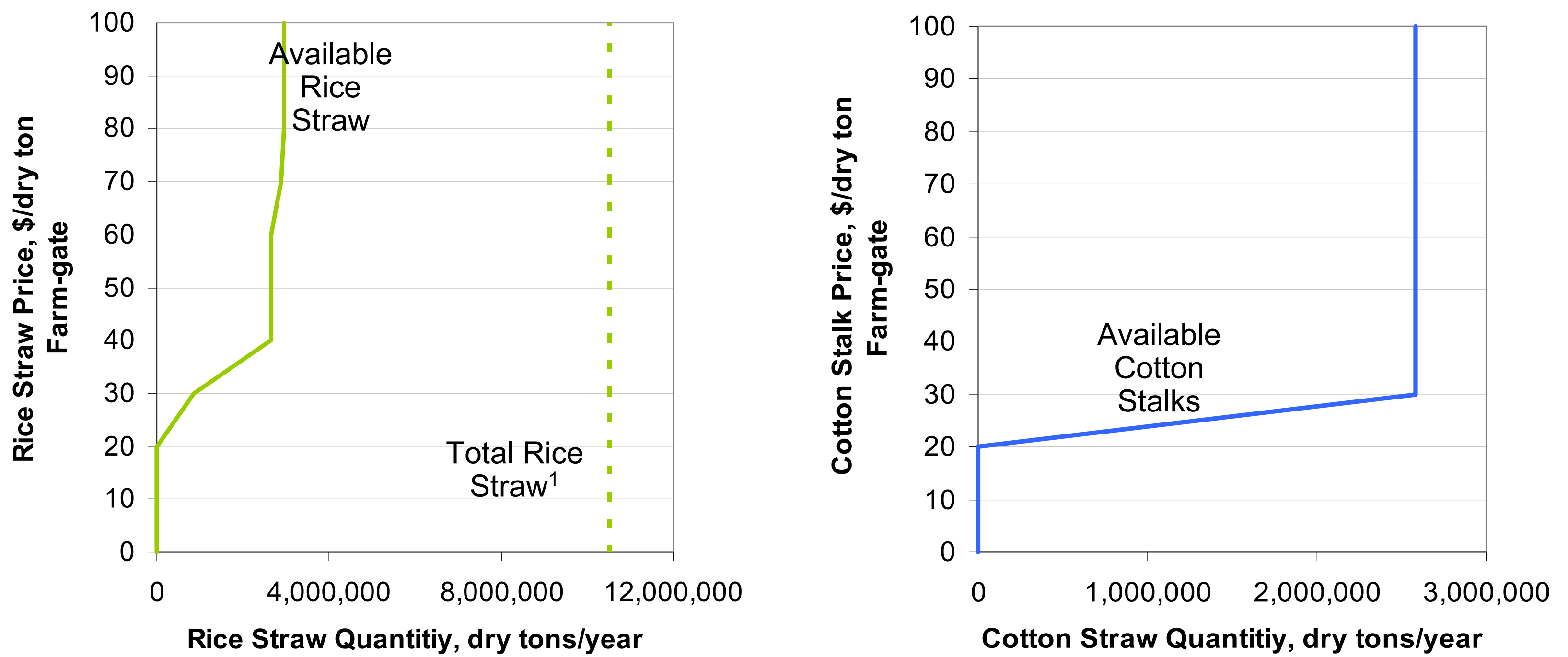
1. Coates, W. E. (1996). "Harvesting systems for cotton plant residue." ASAE Applied Engineering in Agriculture **12**(6): 639-644.



1. Totals are the product of 1999 crop production, according to the USDA, and residue to grain ratios of 1:1 for corn.
2. Total is the product of 1999 crop production, according to the USDA, and residue to grain ratios of 1.5:1 for wheat.

Agricultural Crop Residues *Rice Straw and Cotton Stalks Supply Curve*

U.S. Agricultural Crop Residue Supply Curves: Rice Straw and Cotton Stalks
Dry Tons per Year Based on Available Quantities at 0-80 $/dry ton Farm-gate



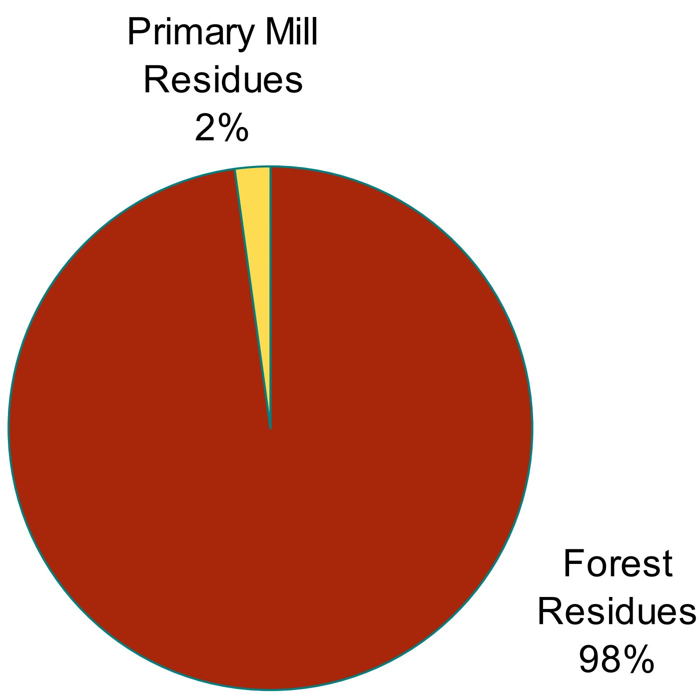
1. Total is the product of 1999 crop production, according to the USDA, and residue to grain ratio of 1:1 for rice.
2. An estimate for total cotton stalk quantities could not be found.

Available quantities of agricultural residues could dramatically increase if the residue is seen as a positive value to farmers.

- Several agricultural production practices could be altered if residues are seen as a positive value:
  - Decreasing the number of planted rows
  - Planting more productive (but higher residue yielding) species
- These practices may result in primary product yield increase, but residue accumulation is traditionally a problem
- However, if residues are collected and sold:
  - Primary product yield still increases;
  - Farmers benefit from a by-product revenue stream (this analysis assumes $10/dry ton);
  - The fraction of residues left in the field could be decreased, resulting in a higher available quantity of residues

Available forest residues overshadows available primary mill residues because most mill residues are already in use.

U.S. Forest and Mill Residue Fractions
Based on Available Quantities at 0-40 $/dry ton Farm-gate



Available Quantity at 0-40 $/dry ton Farm-gate = 85.5 million dry tons/year

Forest residue state-level quantity and price data is based on an analysis by Oak Ridge National Laboratory (Perlack, 2000).

- State-level available quantities include total logging residues and live cull and sound dead wood[1] revised downward using recoverability factors based on:
  - Retrieval efficiency - assumes 50% can be recovered with existing technology and equipment;
  - Site access (roads) - assumes 40% of live cull and sound dead resource, and 90% of logging residues are accessible;
  - Steep slopes - portion of inventory on steep slopes (>20% slope) is considered not recoverable for cost and environmental reasons (~50% of total)
- State-level costs include collection, harvesting, chipping, loading, hauling, unloading, and return for profit and risk
  - Costs do not include gaining access to a site (e.g., temporary roads) and transportation to an end-use location
- ORNL data is an updated version of an analysis by McQuillan et al. (1994) and Decision Analysis Corporation (1995).
  - Updates recoverability factors and inventory data (using the most recent USDA/Forest Service data)
  - Excludes sapling trees and small pole trees
  - Adds a nominal stumpage fee ($2/dry ton) and eliminates transportation costs
  - Converts 1980$ to 1998$

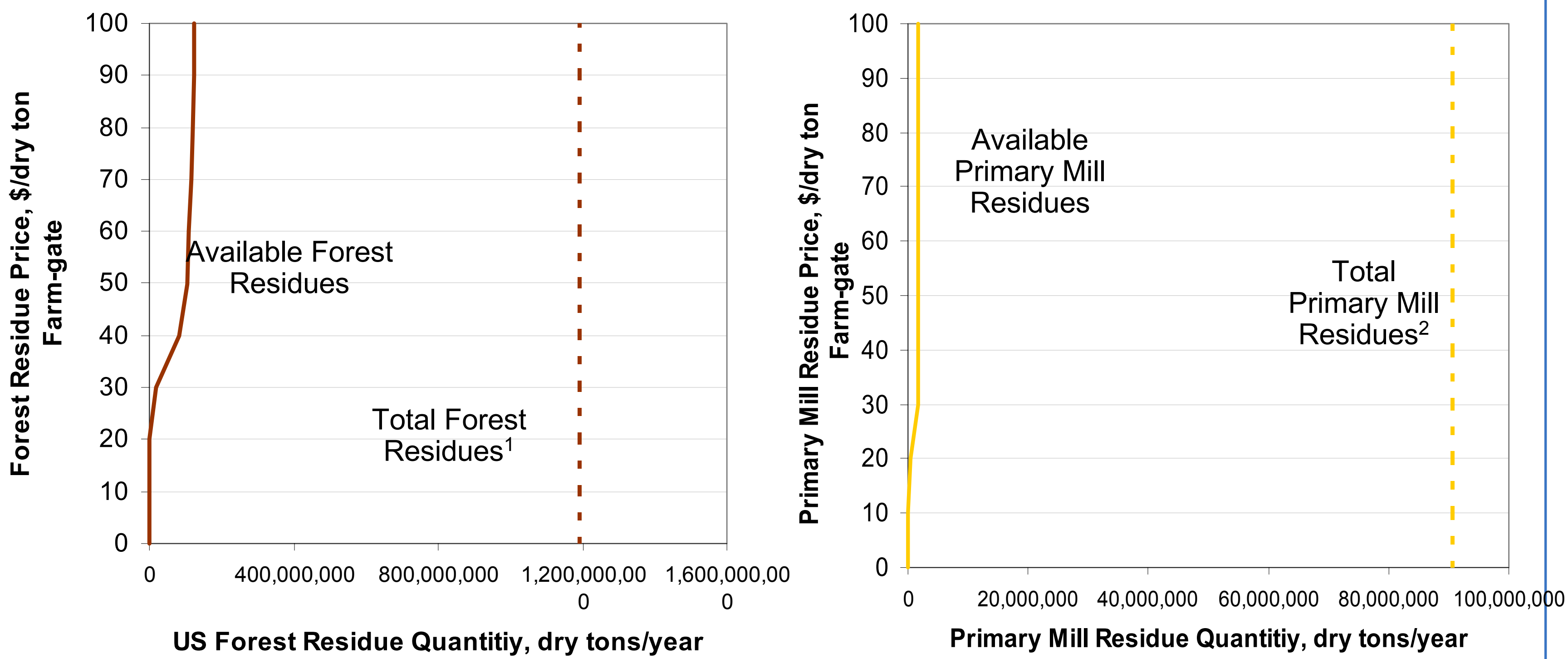
[1] As defined and determined by the U.S. Forest Service (USFS, 1997).

Primary mill residues state-level quantity and price data is based on U.S. Forest Service (USFS, 1997) and NREL data (Rooney, 1998).

- State-level available quantities are based on U.S. Forest Service data
  - Includes bark, coarse material, and fine material from primary mills
  - Data is based on primary mill estimates[1]
  - We included quantities not used (burned and landfilled), but excluded all other uses (fuelwood, fiber, and miscellaneous byproducts)
- State-level prices are based on a report for NREL
  - Prices are for those mill residues currently sold (used)
  - Price estimates were obtained from EIA data which is based on information obtained from mill residue producers, marketers, and end users
  - Weighted average prices were calculated, taking into account the relative composition of coarse and fine bark residues in states

[1] Some experts feel that the unused quantities of residues are underestimated by some mills.

U.S. Forest and Mill Residue Supply Curves: Forest Residues and Primary Mill Residues
Dry Tons per Year Based on Available Quantities at 0-80 $/dry ton Farm-gate



1. Total residues is based on U.S. Forest Service data and includes live cull wood, sound dead wood, and logging residues. Assumes 38 lbs/ft3 and 15% moisture content.
2. Total according to U.S. Forest Service data (USFS, 1997).

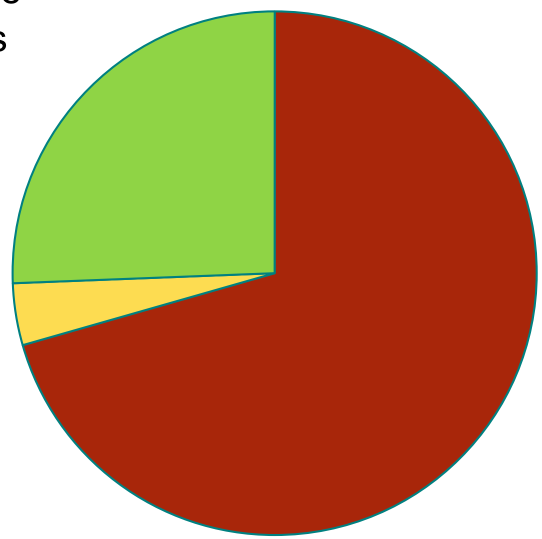
Forest and mill residues potentially could have much higher quantities and lower cost than estimated.

- Forest residues have potential to be much cheaper if their collection is subsidized for fire protection
  - Paying $300/acre to remove forest residue in the form of a subsidy, would result in a reduction of around $20/dry ton[1] from the price of forest residues
  - While the current "controlled burn" forest fire prevention practice is cheap when all goes well, the actually cost to taxpayers is substantial if the fires become uncontrollable
- Available primary mill residues may have higher quantities then estimated here
  - Some experts we have interviewed feel that some primary mills may underestimate the quantity of unused residues

1. Assuming 15 dry tons of forest residues could be collected per acre.

The organic fraction of municipal solid waste is a major unused biomass resource in the U.S..

U.S. Other Waste Fractions
Based on Available Quantities at 0-40 $/dry ton Farm-gate



Available Quantity at 0-40 $/dry ton Farm-gate = 161 million dry tons/year

Organic MSW state-level quantity and price data is based on EPA (Franklin Associates, 1999) and BioCycle analyses (Glenn, 1998).

- We used an EPA estimate of the total MSW generated and broke it out by state using U.S. Census Bureau population data
- We determined available MSW (organic and inorganic) quantities based on BioCycle landfill fraction data
  - State-level landfill fractions (excludes incinerated and recycled MSW) are subtracted from the total amount generated in each state
- We used an EPA estimate of the total organic fraction to obtain organic MSW quantities
- We used MSW state landfill tipping fees from BioCycle to determine organic MSW cost
  - We assume the residue is free if state tipping fee is greater than \$15/ton and \$10/dry ton if state tipping fee is less than \$15/ton[1]
  - In the case of MSW, all tipping fees reported were less than \$15/ton

1. Tipping fee refers to a fee paid by the waste generator to the disposal facility for landfilling, incinerating, or otherwise disposing of the waste. State tipping fee refers to the average tipping fee for landfill facilities in the state.

C&D wood state-level quantity and price data is based on ORNL (Walsh personal communication) and BioCycle analyses (Glenn, 1998).

- We used ORNL state-level construction and demolition wood waste quantities
  - Estimated state-level unused quantities based on the number of C/D landfills by state and average quantity of waste received per C/D landfill by region
  - We included C&D wood used for landcover, other uses, and 80% of compost use[1] as the "unused" portion
- We assumed 50% of the "unused" quantity would be "usable" based on a report for the Northeast Regional Biomass Program (Fehrs, 1999)
  - The report indicates that 70% of demolition wood wastes and 24% of construction wood wastes cannot be used due to commingling and contamination
  - Therefore, we assume that 50% of the "unused" portion is "available"
- C&D and UTR state landfill tipping fees from the BioCycle article were used to determine C&D wood prices
  - We assume the residue is free if state tipping fee is greater than \$15/ton and \$10/dry ton if state tipping fee is less than \$15/ton[2]

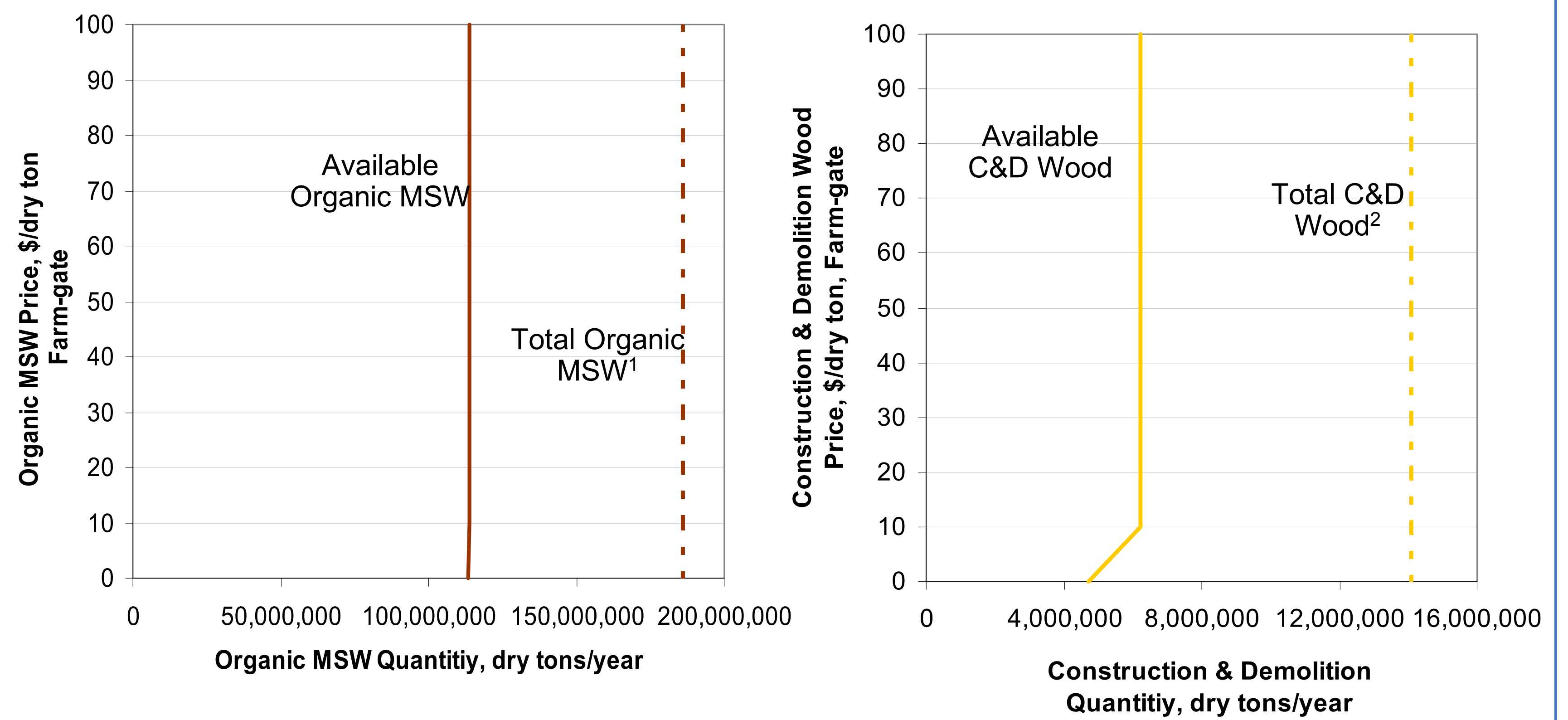
1. We assumed that 20% of compost in current use is beneficial, based on EPA data (Franklin Associates, 1998) that 18% of compost is sold to nurseries or bagged and sold retail.
2. Tipping fee refers to a fee paid by the waste generator to the disposal facility for landfilling, incinerating, or otherwise disposing of the waste. State tipping fee refers to the average tipping fee for landfill facilities in the state.

UTR state-level quantity and price data is based on a report for NREL (Rooney, 1998) and Allegheny Power System (NEOS, 1994).

- We used NREL's state-level quantities of urban tree residues broken out by type (chips, logs, tops/brush, mixed wood, leaves, grass, and stumps) to obtain total quantities
  - This work was based on a nation-wide mail and telephone survey of arbor-culture and urban forest industries
- We used the Allegheny Report national average data to determine available quantities and cost
  - We subtracted the waste-to-energy and sold fractions by type to obtain available quantities
  - We assumed the fraction landfilled could be obtained for free, to avoid tipping fees, and the remainder (given away, left on site, open burned, recycled, and used on site) would cost $10/dry ton

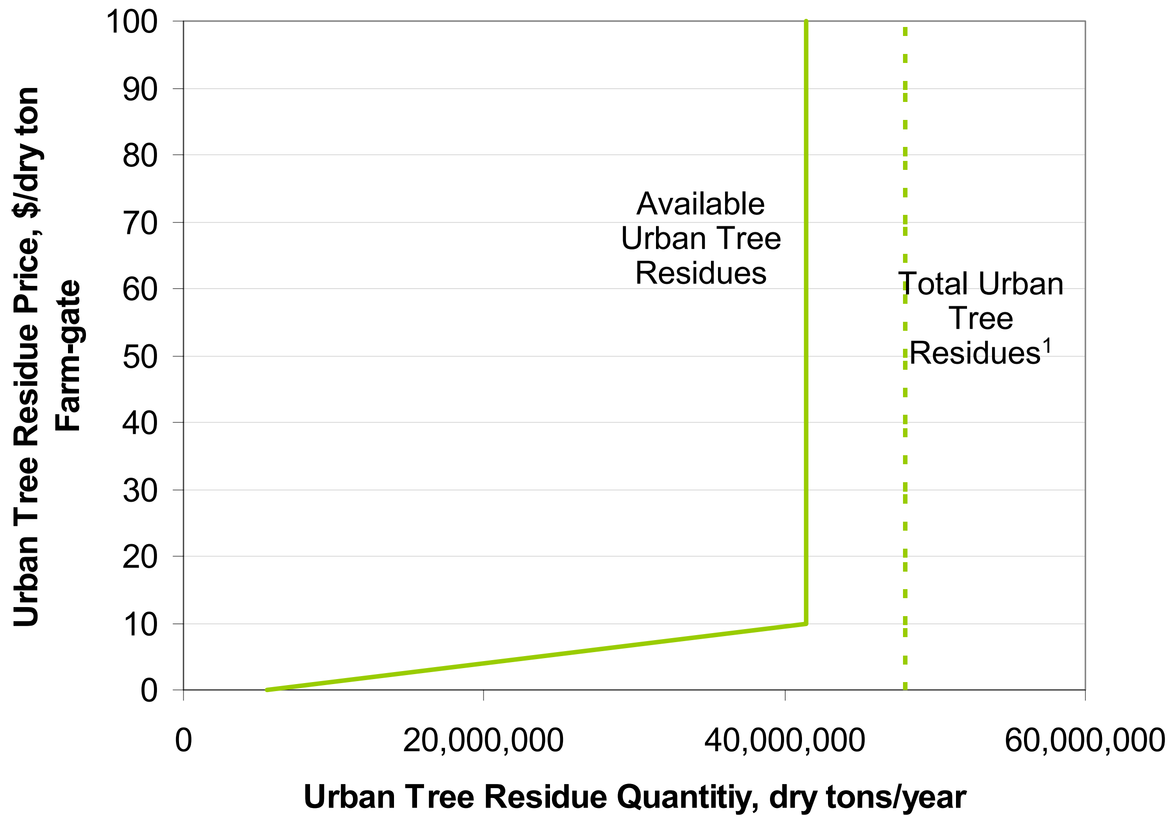
U.S. Other Wastes Supply Curves: Organic MSW and Construction & Demolition Wood

Dry Tons Per Year Based on Available Quantities at 0-80 $/dry ton Farm-gate



1. Total according to U.S. EPA data.
2. Total according to ORNL data.

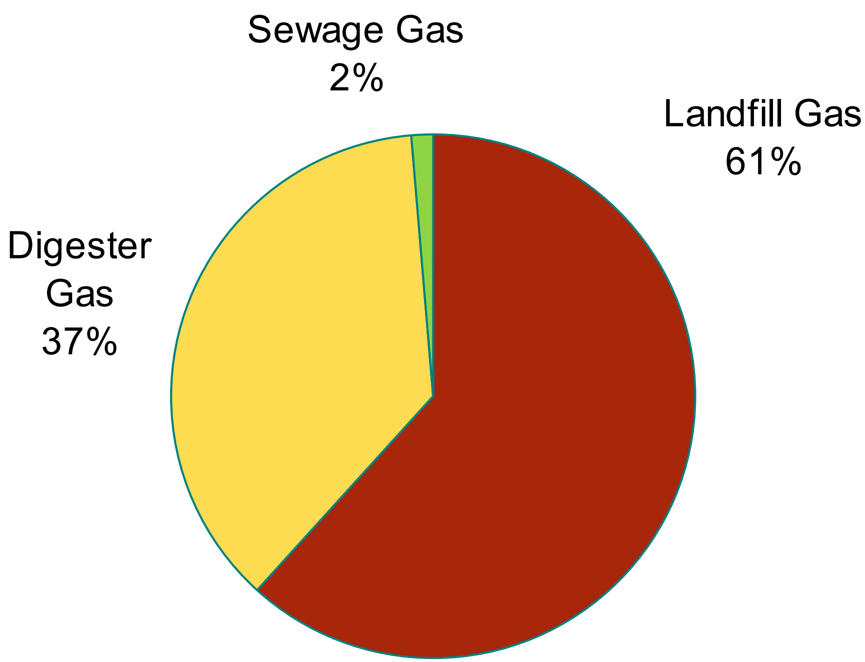
U.S. Other Wastes Supply Curves: Urban Tree Residue Supply Curve
Dry Tons Per Year Based on Available Quantities at 0-80 $/dry ton Farm-gate



1. Total according to a report prepared for NREL (NEOS, 1998).

Landfill gas and digester gas offer an important low-cost opportunity for biomass utilization.

U.S. Biogas Fractions
Assumption: Biogas is available at zero cost and used on-site



Available Quantity at 0-40 $/dry ton[1]
= 11.3 million dry tons/year [2]

1. This analysis assumes all biogas is available at no cost and is used on-site. Quantity data is for current manure management practices only, therefor, digester construction costs are not included.
2. Assumed gas density of 19.2 g/scf.

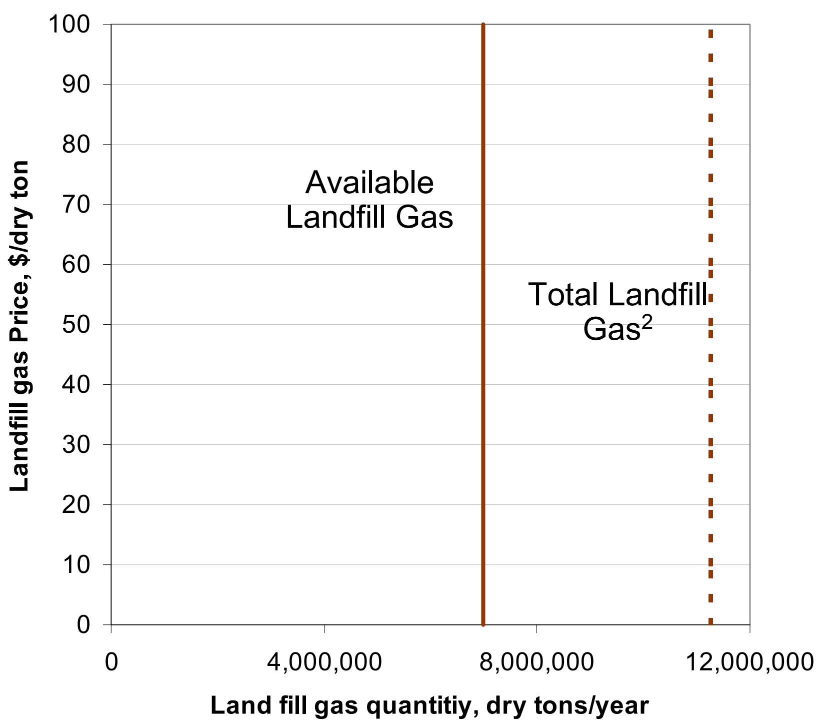
Landfill gas, digester gas, and sewage gas quantities are estimated using EPA data.

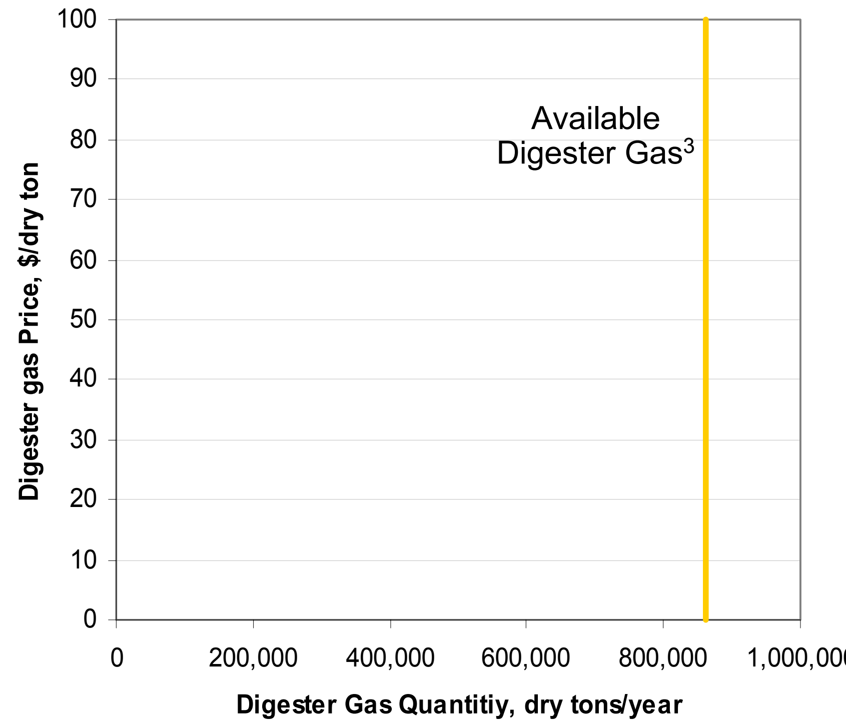
- We used EPA state-level recoverable landfill gas volumes (EPA, 1999A) to obtain quantity information
  - Included “candidate”, “shutdown” and “other” projects; “current” projects were excluded (Already in use)
  - Assumed gas density of 19.2 gm/scf
  - We assume all is available at zero cost and is used on-site
- We used EPA state-level manure methane emissions data[1] to estimate digester gas quantities
  - Estimated methane emissions based on USDA animal population data, estimated manure volatile solids production by animal, state weighed methane emissions factors, and other scaling factors
  - Takes into account animal type and current manure management practices
  - We assume all is available at zero cost and is used on-site
  - Quantity data is for current manure management practices only, therefore, digester construction costs are not included
  - Revised, unpublished (as of 2/2000) data indicates that quantities may be much lower than reported here[1]
- We used EPA national waste water emissions data[2] and U.S. Census population data to estimate state-level quantities of sewage gas
  - We assume all is available at zero cost and is used on-site

1. Tom Wirth of the EPA Climate Policy team; and U.S. EPA, Office of Air and Radiation. September 1999. “U.S. Methane Emissions 1990-2020: Inventories, Projections, and Opportunities for Reductions”.
2. According to the EPA website, “EPA Global Warming Site: National Emissions - Methane”, http://www.epa.gov/globalwarming/emissions/national/methane.html.

Biogases Landfill Gas and Digester Gas Supply Curve

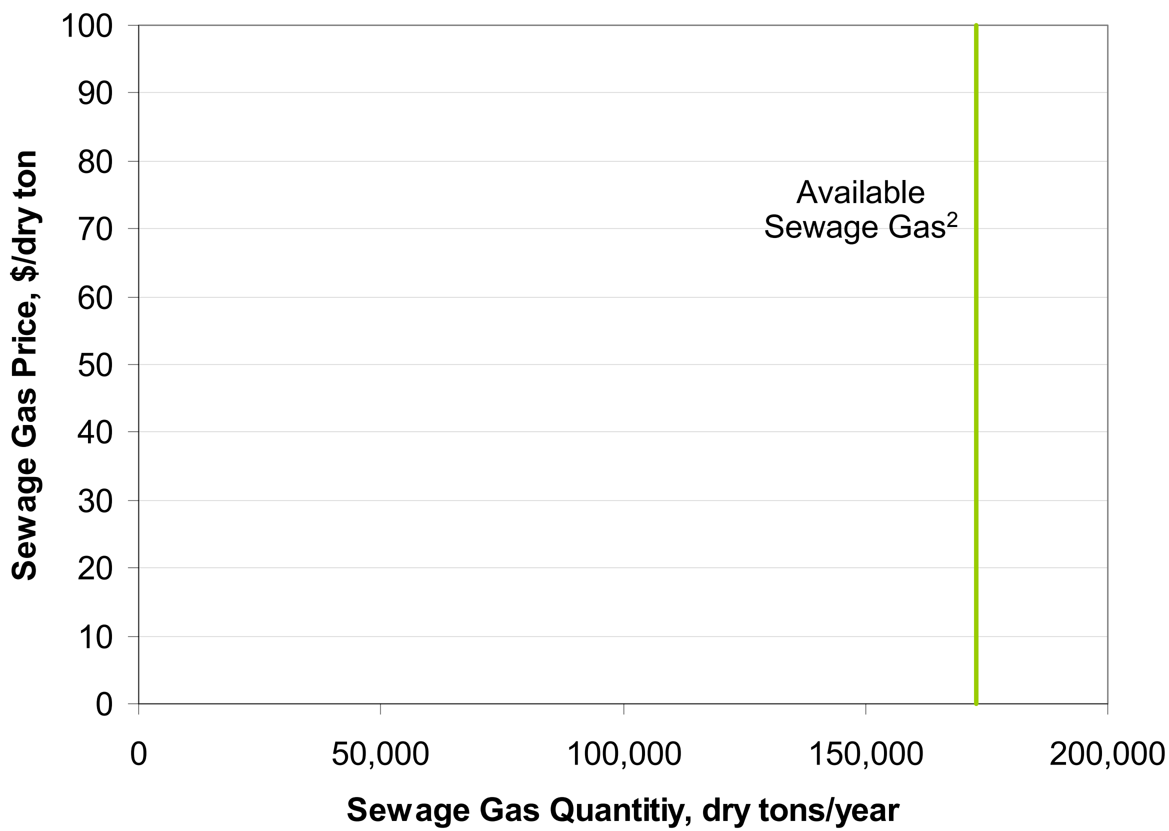
U.S. Biogas Supply Curves: Landfill gas and Digester Gas
Dry Tons Per Year Biogas are available at zero cost and used on-site





1. This analysis assumes all biogas is available at no cost and is used on-site. Assumed gas density of 19.2 g/scf.
2. Total according to U.S. EPA Landfill Methane Outreach Program data.
3. Total digester gas quantities were not found in the literature.

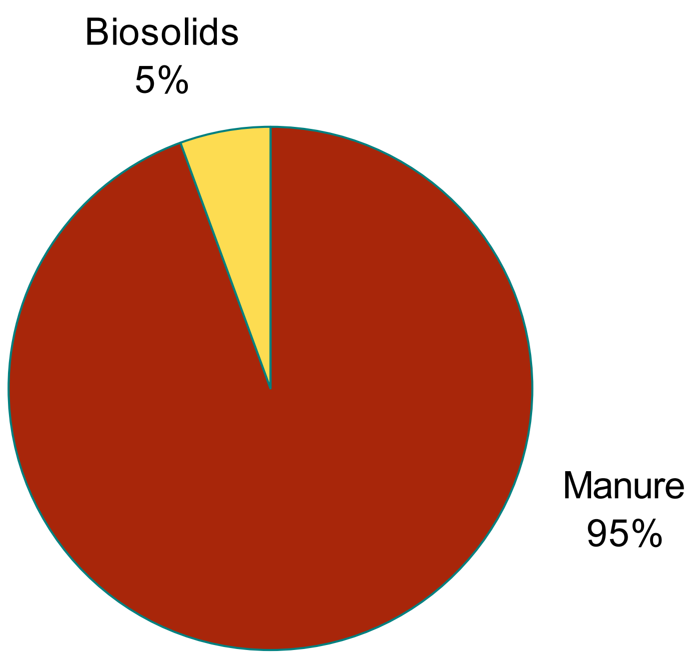
U.S. Biogas Supply Curves: Sewage Gas
Dry Tons Per Year Biogas are available at zero cost and used on-site



1. This analysis assumes all biogas is available at no cost and is used on-site. Assumed gas density of 19.2 g/scf.
2. Total sewage gas quantities were not found in the literature.

Manure offers a potentially large and low-cost opportunity for biomass utilization.

U.S. Sludge Fractions
Sludges are available at zero cost and used on-site



Available Quantity at 0-40 $/dry ton Farm-gate
= 50.5 million dry tons/year

1. This analysis assumes all sludge is available at zero cost.

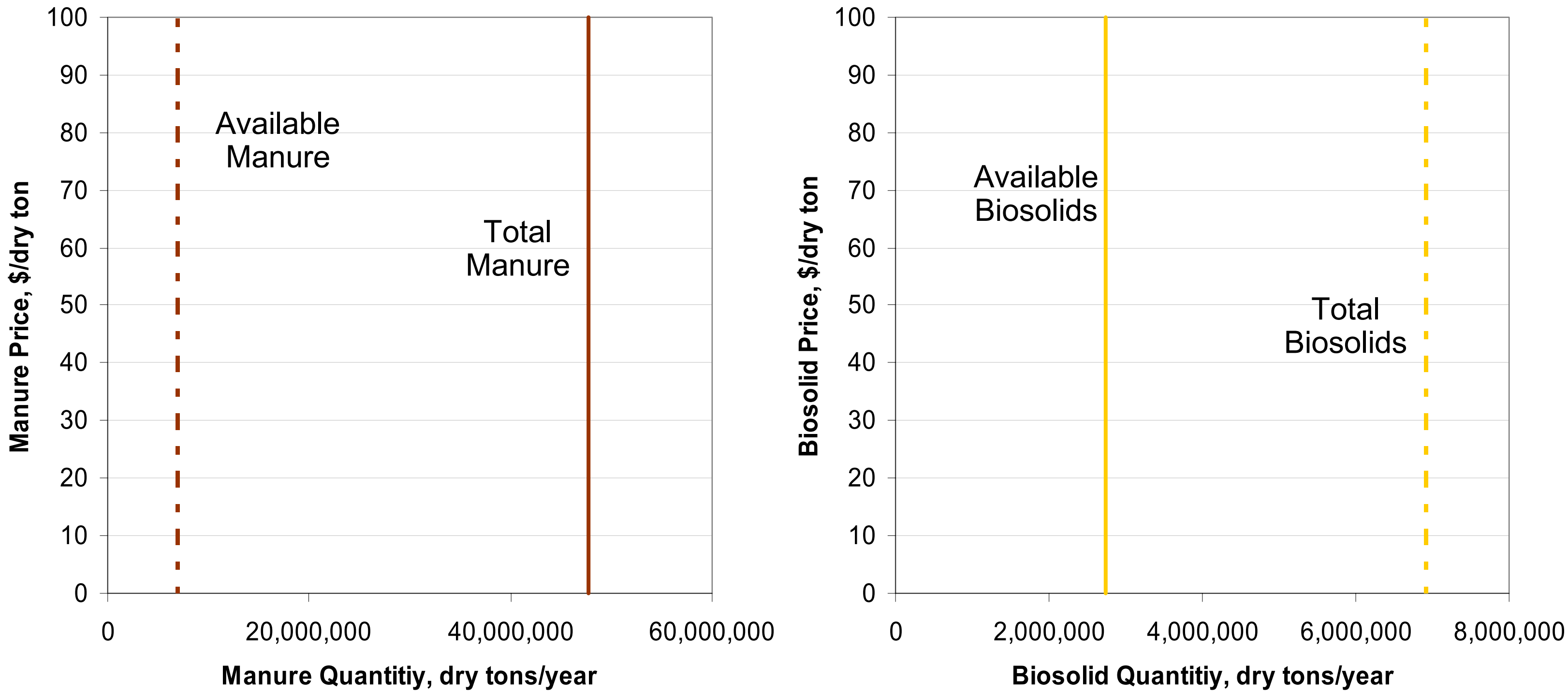
Manure and biosolids quantities are estimated using EPA data and state-level population data.

- We used EPA national animal waste production data, along with state-level animal population and manure management data to estimate quantity
  - EPA data (EPA, 1998) provided national total manure production for seven animal categories
  - USDA state-level animal population data was used to break down the national totals
  - Additional EPA data (EPA, 1999A) provided manure management practices by state
    - We assumed all manure applied to the land is either uncollectable or in use as a soil amendment
    - Therefore, the fraction applied to the land ("daily spread" or "pasture") was excluded from the available quantity
  - We assume all is available at zero cost and is used on-site
- We used EPA national biosolids disposal data (EPA, 1999A) and U.S. Census population data to estimate state-level quantities
  - EPA estimates total biosolids production and end uses
  - Beneficial uses (land application, advanced treatment[1], and other) were excluded, but disposal uses (surface disposal/landfill, incineration, and other) were included in the available quantity
  - We assume all is available at zero cost and is used on-site

1. Includes composting.

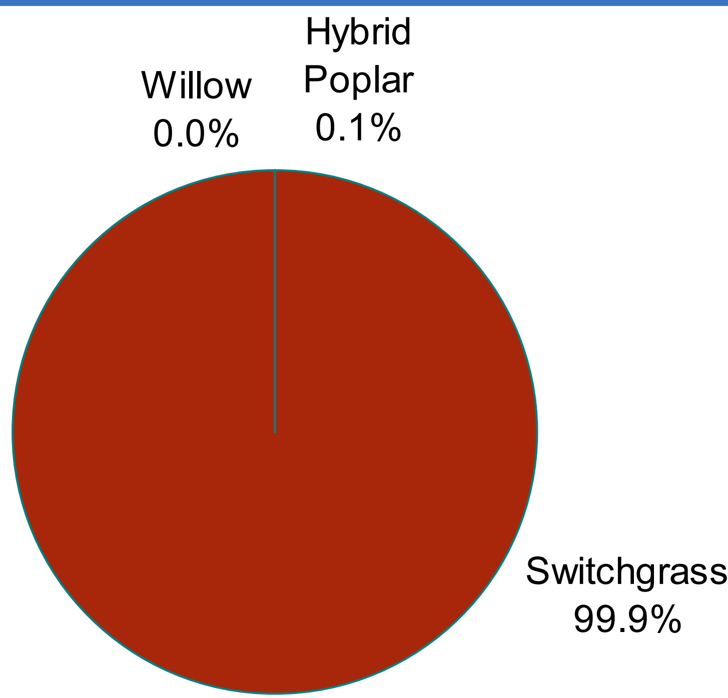
U.S. Supply Curves: Manure and Biosolids

Dry Tons Per Year, Sludges are available at zero cost and used on-site



The overwhelming fraction of biomass from energy crops at 0-40 $/dry ton farm-gate could come from switchgrass.

U.S. Potential Energy Crop Fractions[1]
Based on Available Quantities at 0-40 $/dry ton Farm-gate



Available Quantity at 0-40 $/dry ton Farm-gate = 159 million dry tons/year

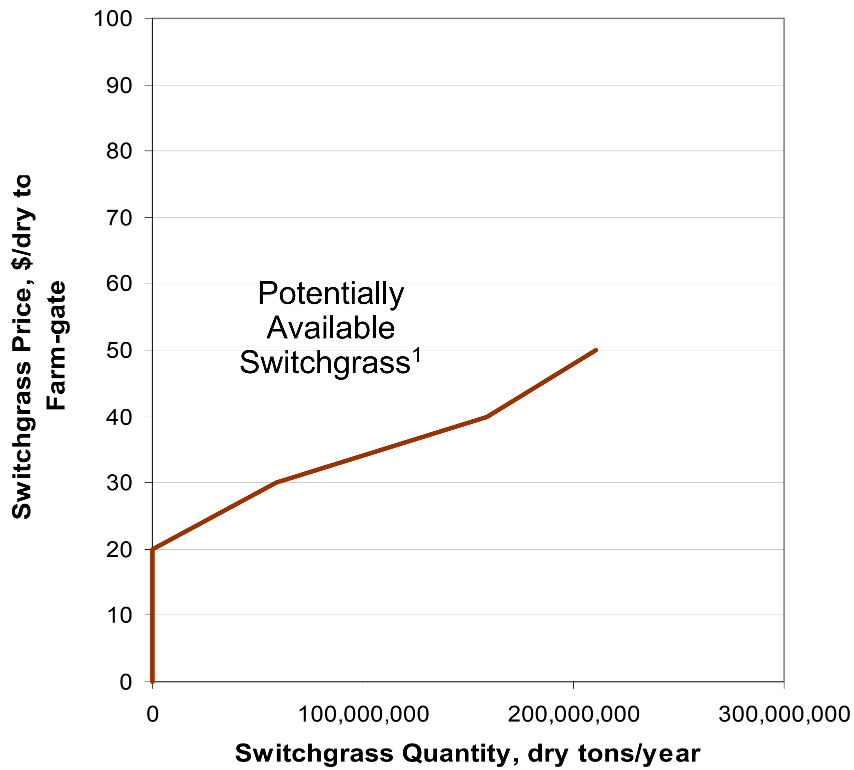
Switchgrass dominates the energy crop category because it is estimated to be slightly cheaper than producing hybrid poplar and willow (on dollars per MMBTU basis).

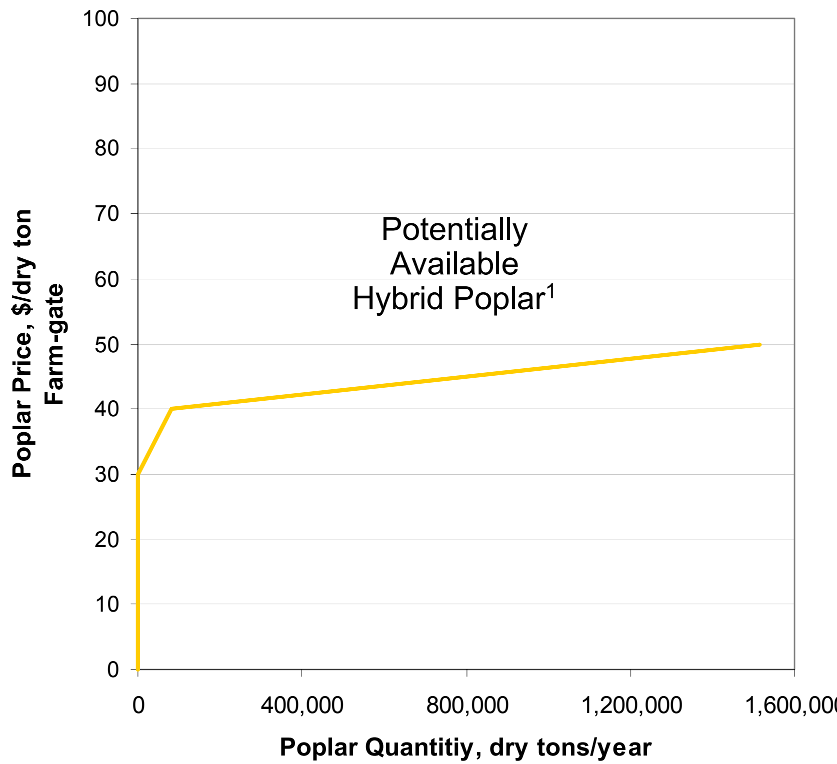
Energy crop state-level quantity and price data is based on ORNL (Walsh et al, 2000) analysis and personal communications.

- ORNL sub-state level data is the result of an agricultural sector model (POLYSYS), modified to include switchgrass, hybrid poplar, and willow
  - Includes all major crops, livestock sector, and food, feed, industrial, and export demand
  - Includes all cropland planted with major crops, idled, in pasture, or in the Conservation Reserve Program
  - Limited to areas climatically suited for energy crop production
- Model estimates quantities of energy crops that could potentially be produced at various prices
  - Allocates acres based on relative profitability in competition with alternative cropland use
  - Costs are estimated using the same approach used by the USDA to estimate costs of producing conventional crops
  - Recommended management practices (planting density, fertilizer and chemical applications, rotation lengths) are assumed
- Switchgrass dominates because it was estimated to be slightly cheaper to produce than hybrid poplar and willow, on a dollars per MMBTU basis
  - If the energy crops were not in direct competition for acres, the quantities of hybrid poplar and willow would be much greater

U.S. Potential Energy Crop Supply Curves: Switchgrass and Hybrid Poplar

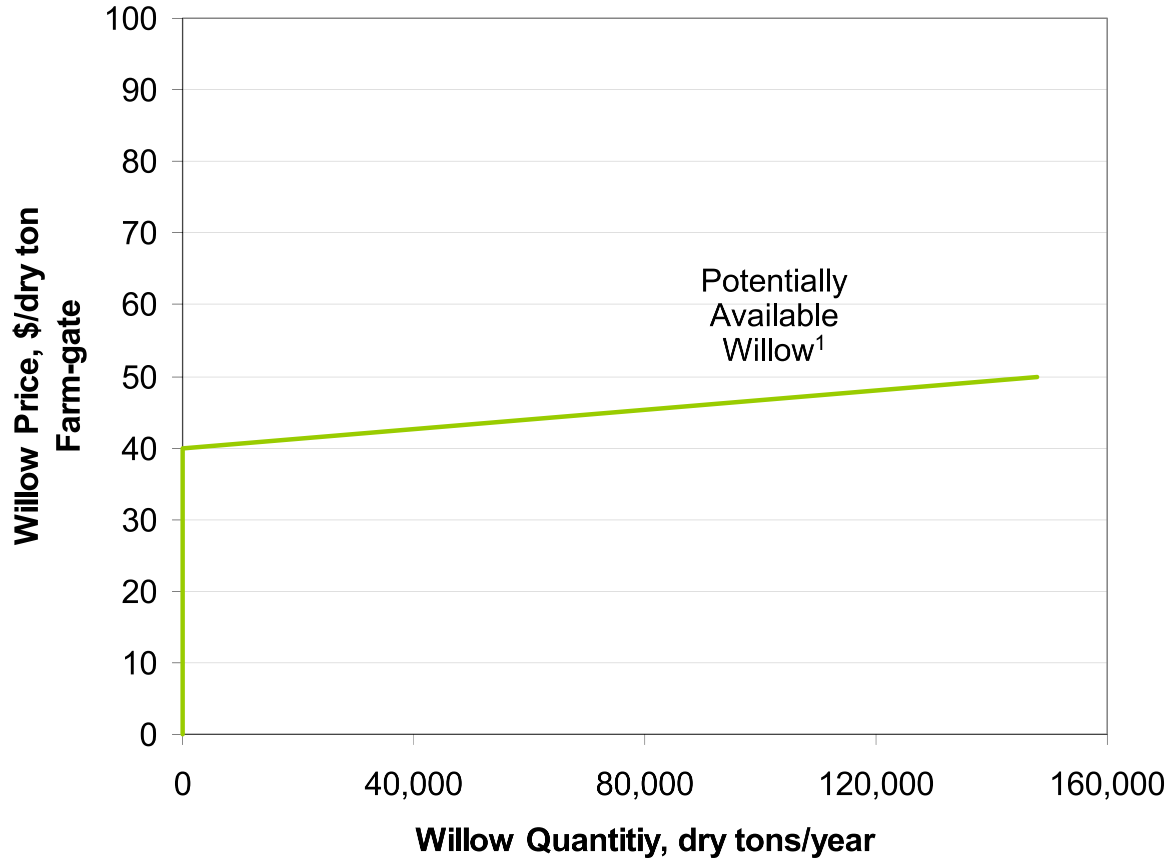
Dry Tons Per Year, Based on Available Quantities at 0-50 $/dry ton Farm-gate





1. Potential energy crop production was not evaluated above $50/dry ton farm-gate.

U.S. Potential Energy Crop Fractions: Willow Supply Curve
Dry Tons Per Year, Based on Available Quantities at 0-50 $/dry ton Farm-gate



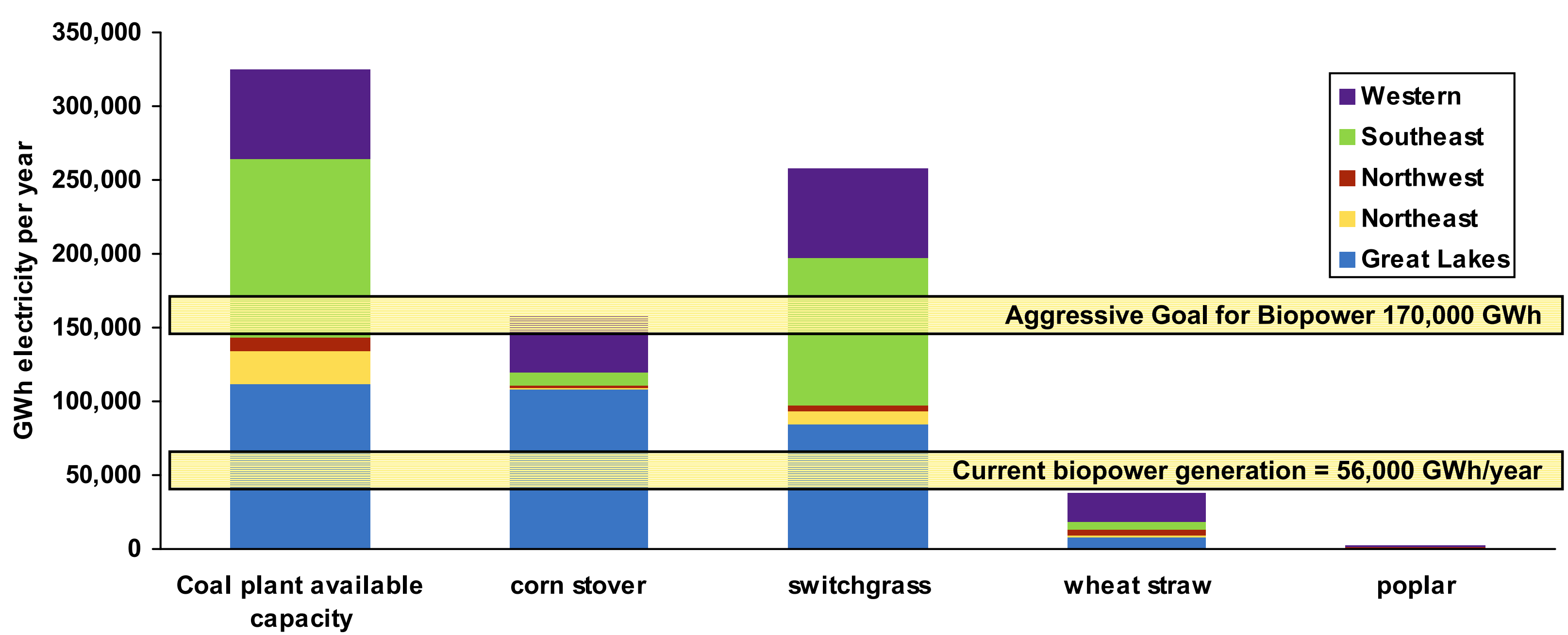
1. Potential energy crop production was not evaluated above $50/dry ton farm-gate.

The following options have been retained for further analysis of benefits and impacts.

All biogas combustion options	• While the technical market potential is modest in size, the economic attractiveness of most options suggests that this "low-hanging fruit" should be developed wherever possible. • Biogas includes landfill gas, sewage gas, and digester gas (e.g. gases from anaerobic digestion)
Co-firing of solid biomass or of gasified biomass	• The economics are nearly competitive with wholesale power (but typically not with the marginal cost of coal-based power) • The large market potential could significantly contribute to the Aggressive implementation goal.
RDF Gasification	• Because the feedstock is available at potential low to zero cost, the economics are attractive. • Because only a small fraction (~15%) of municipal waste is combusted for energy today, this leaves a very large untapped market potential.
Gasification of process wastes	• Where onsite waste fuels are available, gasification technology could be cost competitive, and have a modest potential market impact. • The cost of biomass IGCC power for sale into the wholesale market is well above the cost of competing conventional technologies, but represents an enormous long term opportunity.

While the bulk density of woody biomass makes it technically easier to co-fire, the largest market potential is for crop residues and energy crops.

Maximum Market Size for Biomass Co-fired with Coal Electricity

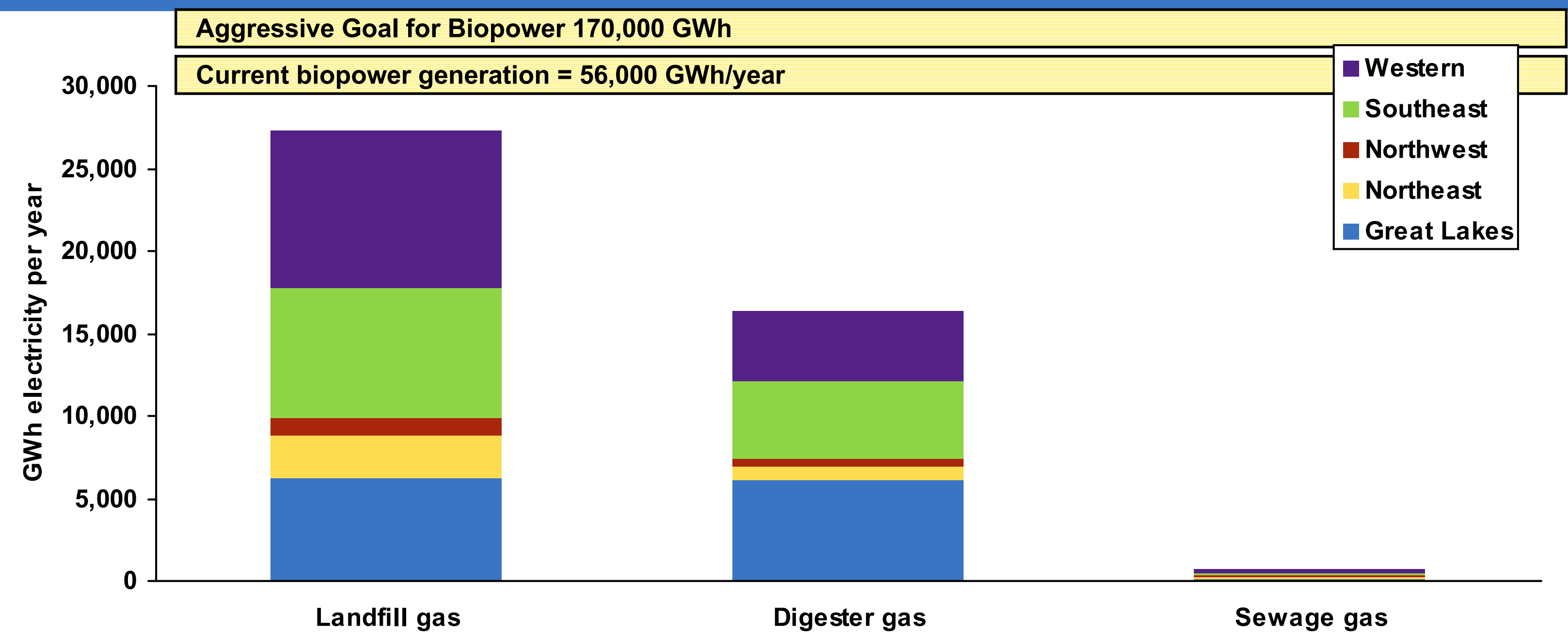


1. Co-firing is coal plant limited. Biomass resource availability assumes that at there must be enough biomass equal to 20% of the coal consumption in the region.
2. The biomass feedstocks address the same coal market so overlap occurs across biomass feedstock market sizes.
3. The numbers reflect using the available resource for a maximum co-firing rate of 15 percent.
4. If biomass over-capacity is present in a particular region, the market shown for that region is the coal capacity in that region.

For comparison, in 1998 there were 1,800,000 GWh of power produced by coal-fired power plants in the U.S. (EIA).

Although the market for biogas fueled power is considerably smaller than solid-fuels due to supply limitations.

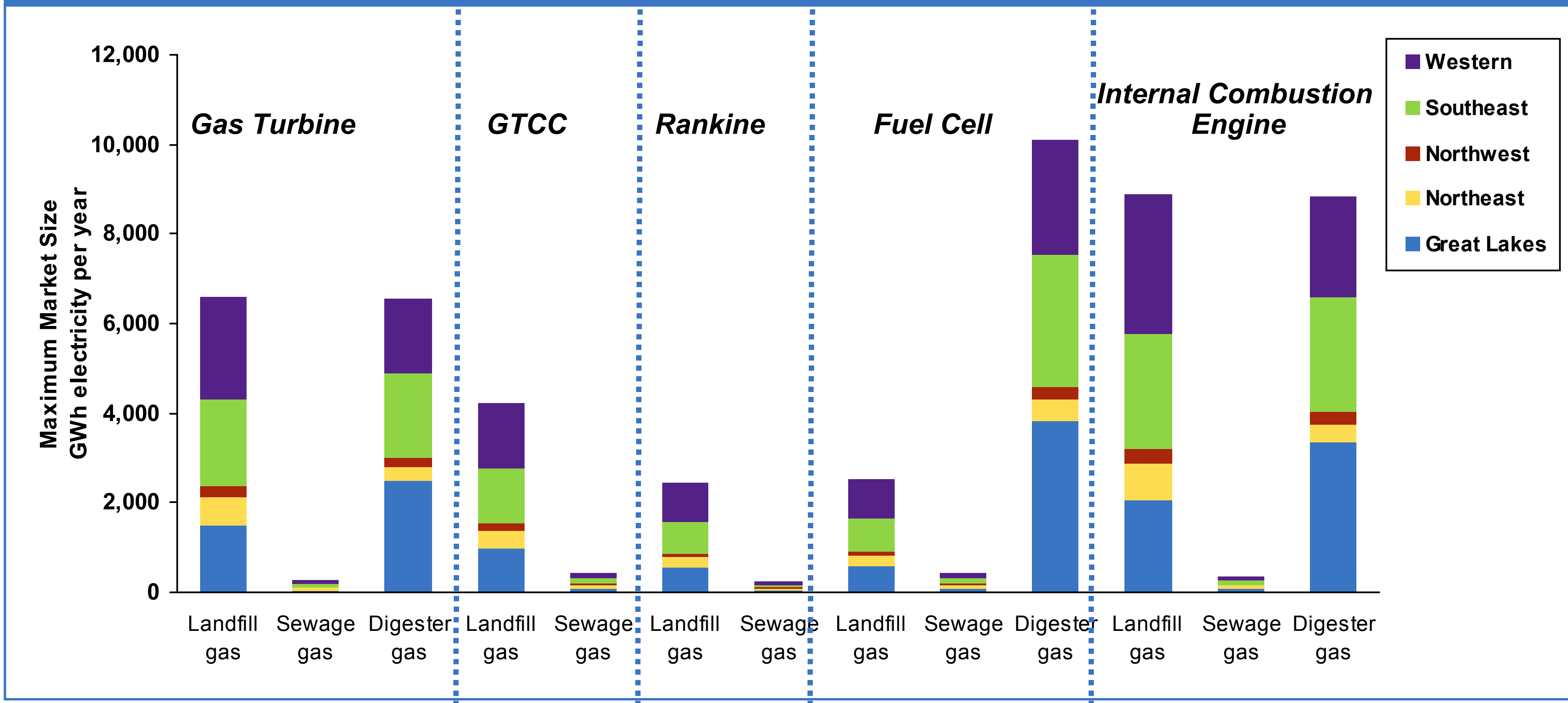
Maximum Market Size for Electricity Generation from Gaseous Biomass



1. The bars represent using the entire resource to generate electricity with an efficiency of 32 percent which includes energy losses from transmission and distribution of 7.2 percent.

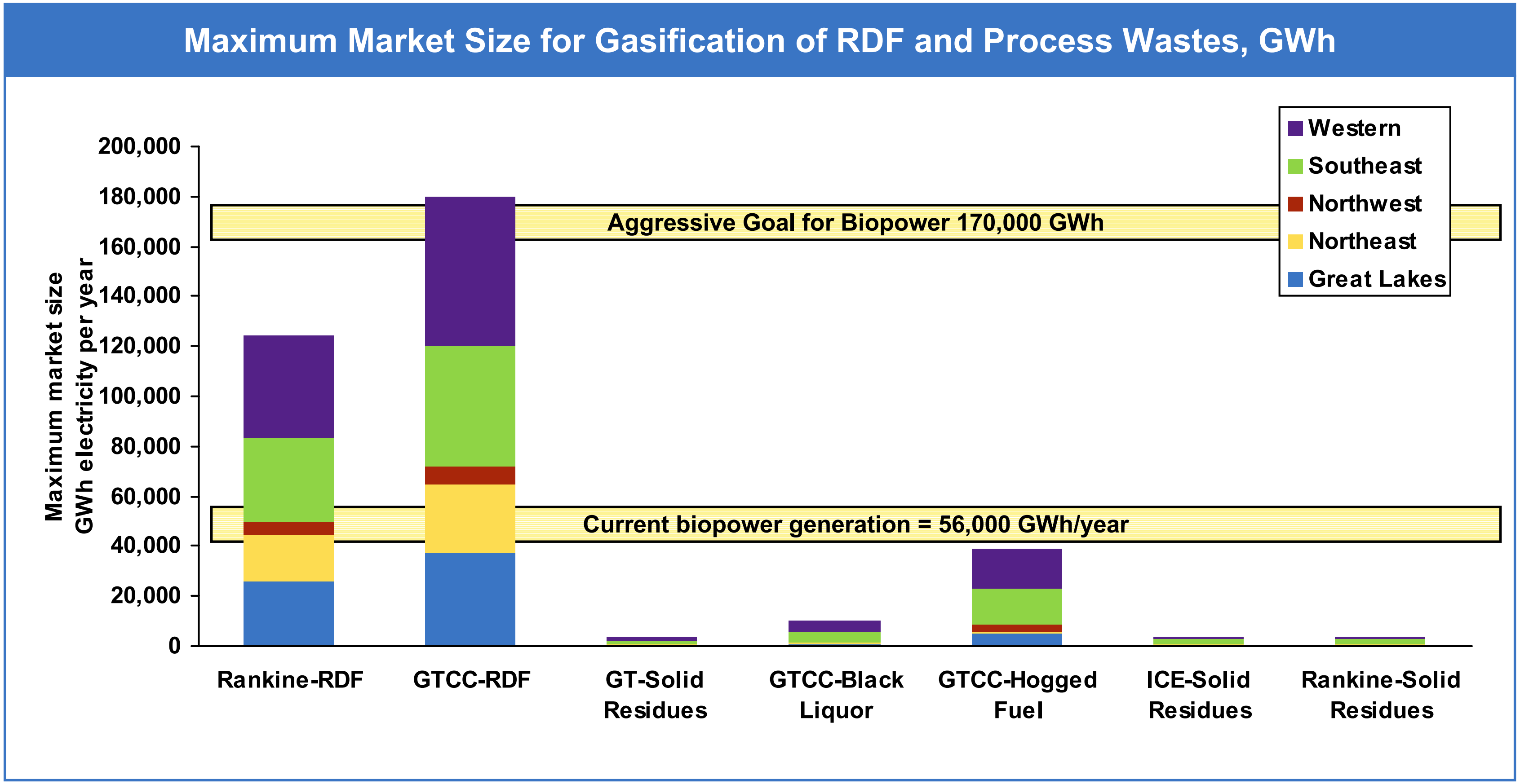
Utilization of landfill gas and digester gas represents the largest opportunity for gaseous biomass utilization for power generation.

Maximum Electricity Market Size for Gaseous Biomass Combustion Options, GWh



1. The bars represent using the entire resource to generate electricity with the associated efficiency with the power generation technology used.
2. Includes energy losses from transmission and distribution of 7.2 percent.
3. Gas turbine and internal combustion engine are used with medium size landfill gas resource which represents 60 percent of the available landfill gas.
4. Gas turbine combined cycle (GTCC) and Rankine technology are used with large size landfill gas resource which represents 25 percent of the available landfill gas.
5. Fuel cell is used with small size landfill gas resource which represents 15 percent of the available landfill gas.

Utilization of RDF and hogged fuel represent promising options for power generation.



1. The bars represent using the entire resource to generate electricity with the associated efficiency with the power generation technology used.
2. Includes energy losses from transmission and distribution of 7.2 percent.

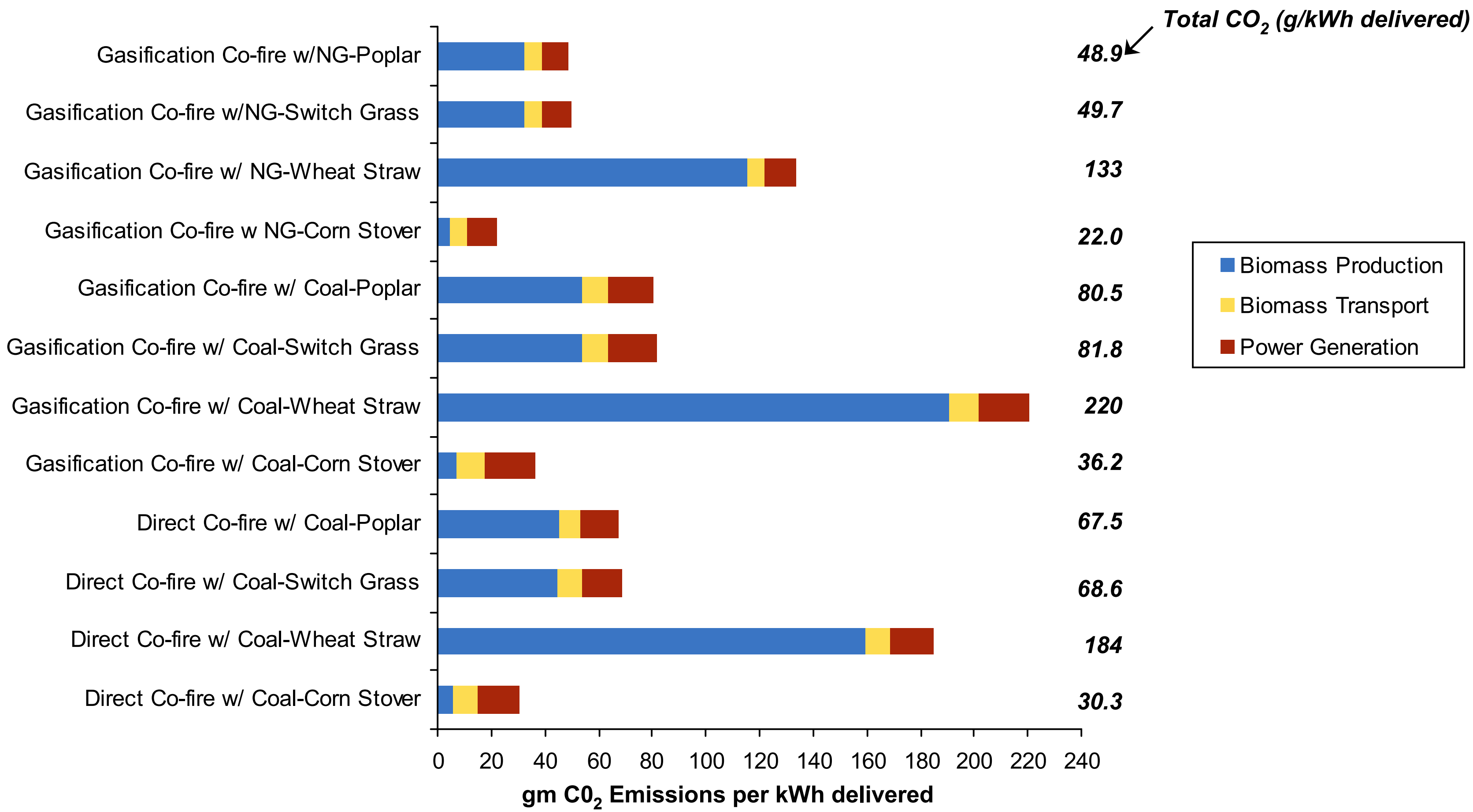
The nature of the biopower opportunities requires that several baselines be developed in order to compare emissions benefits and impacts.

Baseline	Applicable Biopower Options	Comments
Existing Coal Power Plants	• Direct combustion – co-firing Rankine cycle (coal) • Gasification – co-firing Rankine cycle (coal)	• Baseline emissions data developed from DOE/EIA data as reported in the *Electric Power Annual 1998.* • Separate baselines developed for each biomass supply region.
New gas-fired gas turbine combined cycle power plants	• Gasification – co-firing GTCC (natural gas) • RDF Gasification • Landfill gas combustion	• Baseline emissions data developed by Arthur D. Little for new, state-of-the-art facilities.
Average mix of the power grid	• Digester (residue) and Sewage gas combustion options • Gasification of process wastes	• Baseline emissions data developed from a variety of sources including the DOE EIA and the U.S. EPA. • Separate baselines developed for each biomass supply region.

All grid power options include transmission and distribution energy losses of 7.2 percent.

Biomass options offer carbon dioxide emission reduction due to the closed carbon cycle.

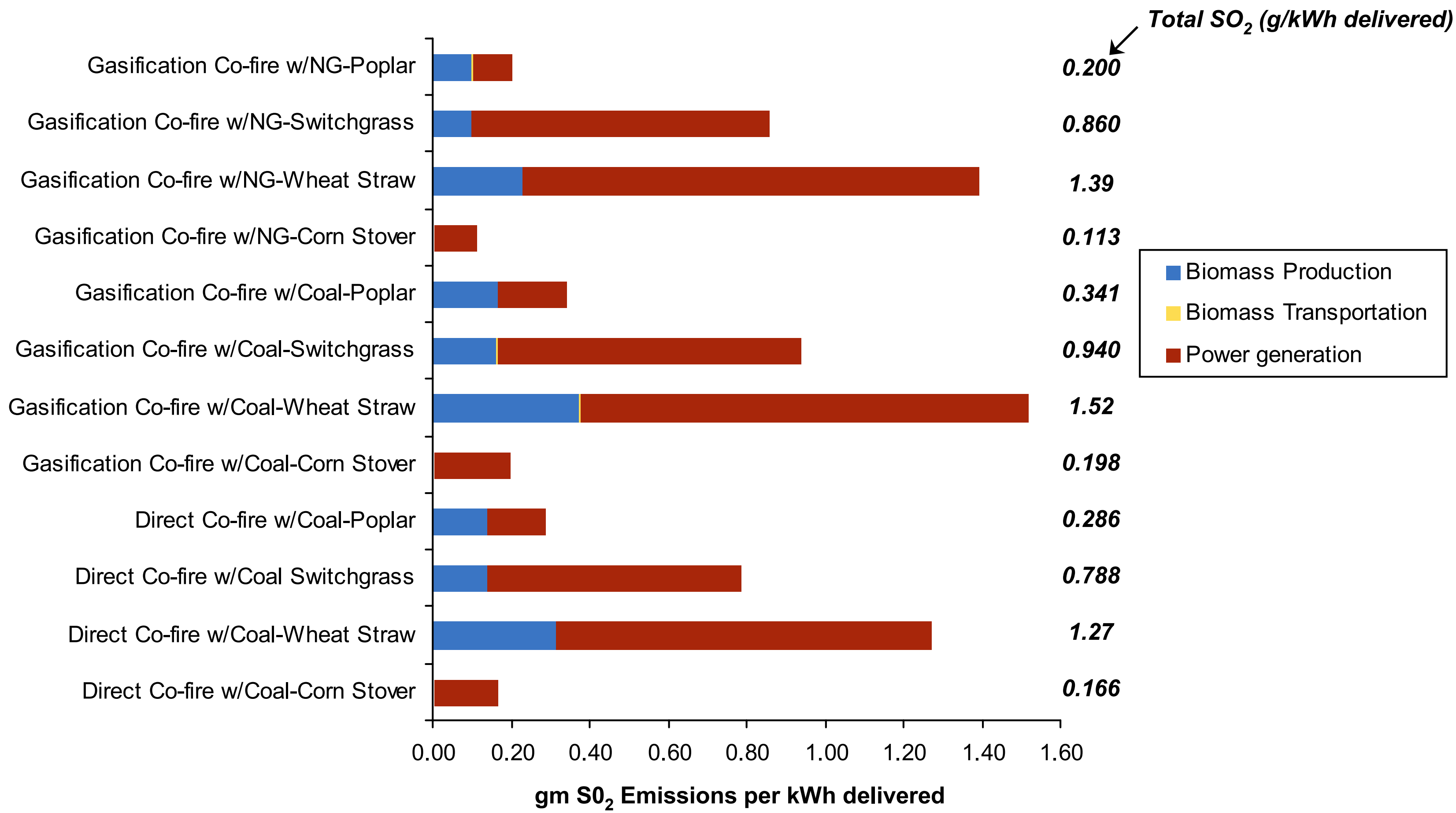
Air Emissions of Co-firing Options: Direct Combustion and Gasification
CO_2 emissions per KWh delivered



1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent. Emissions of a natural gas combined cycle plant 371 g/kWh. National electricity mix emissions 642 g/kWh. Emissions of a Coal fired plant 1054 g/kWh

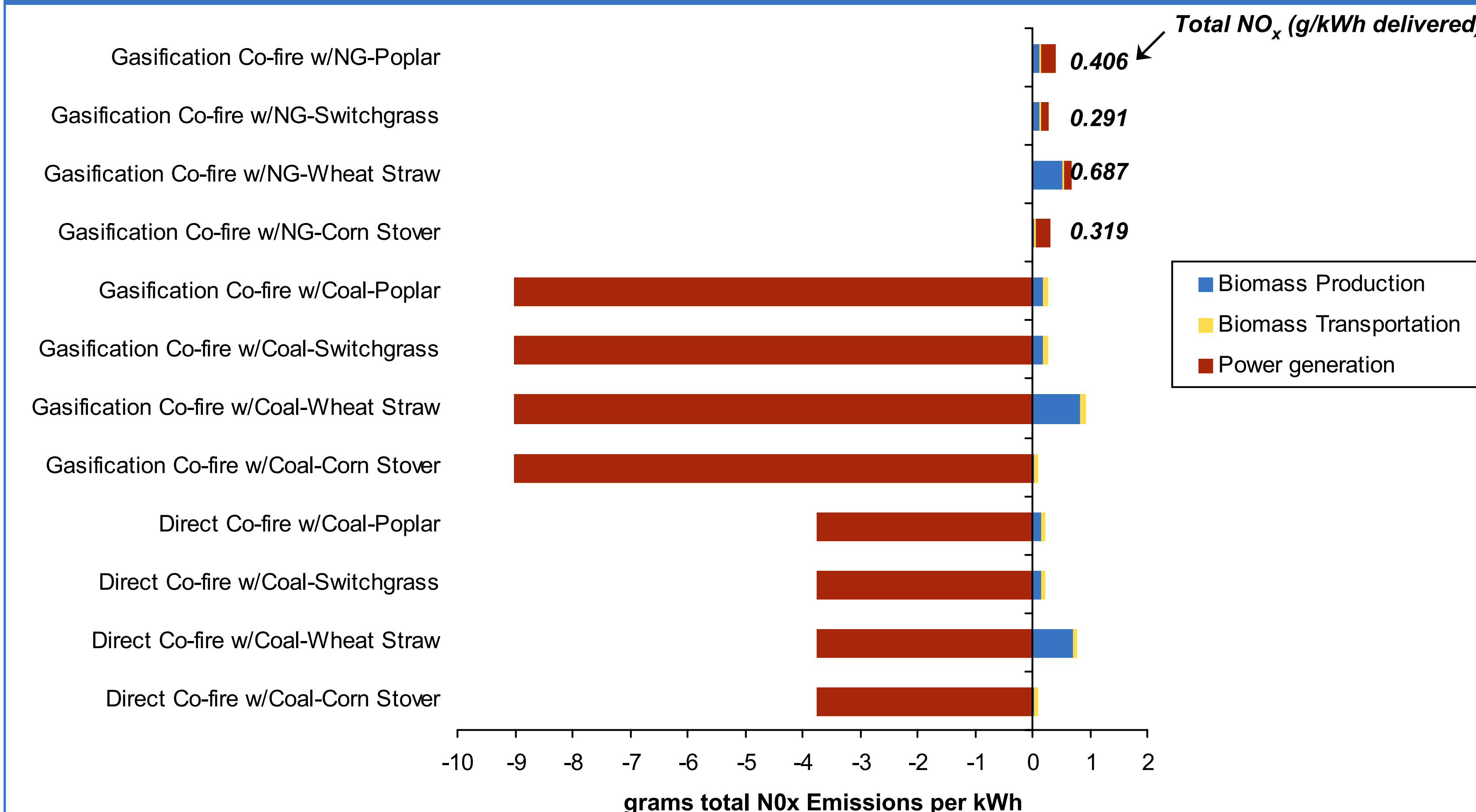
The low sulfur content of biomass offers benefits compared to coal plant and national electricity mix emissions.

Air Emissions of Co-firing Options: Direct Combustion and Gasification
SO_2 emissions per KWh delivered



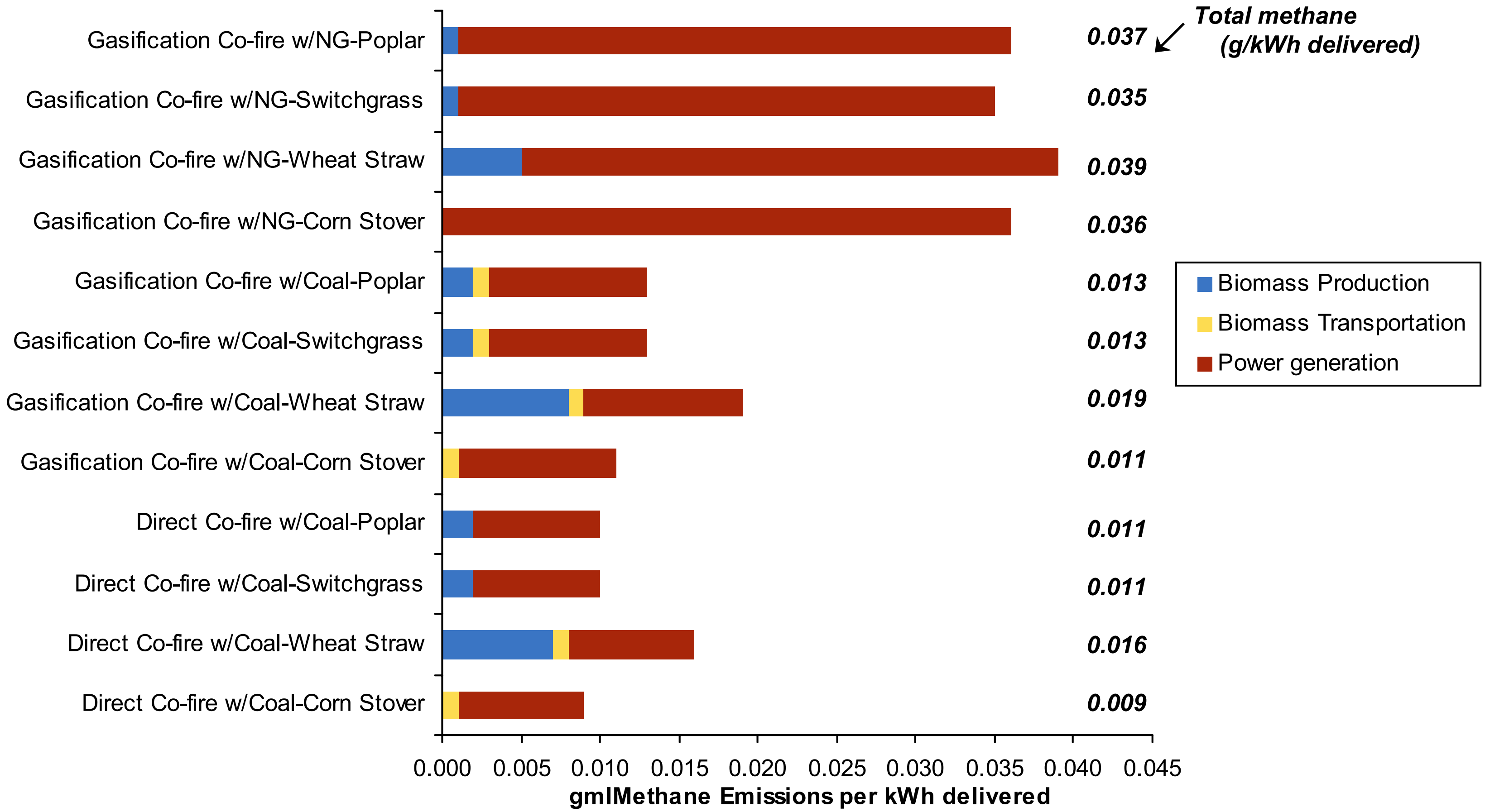
1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent. Emissions of a natural gas combined cycle plant 0.004 g/kWh. National electricity mix emissions 3.1 g/kWh. Emissions of a Coal fired plant 6.1 g/kWh

Air Emissions of Co-firing Options: Direct Combustion and Gasification
gm NO_x emissions per KWh delivered

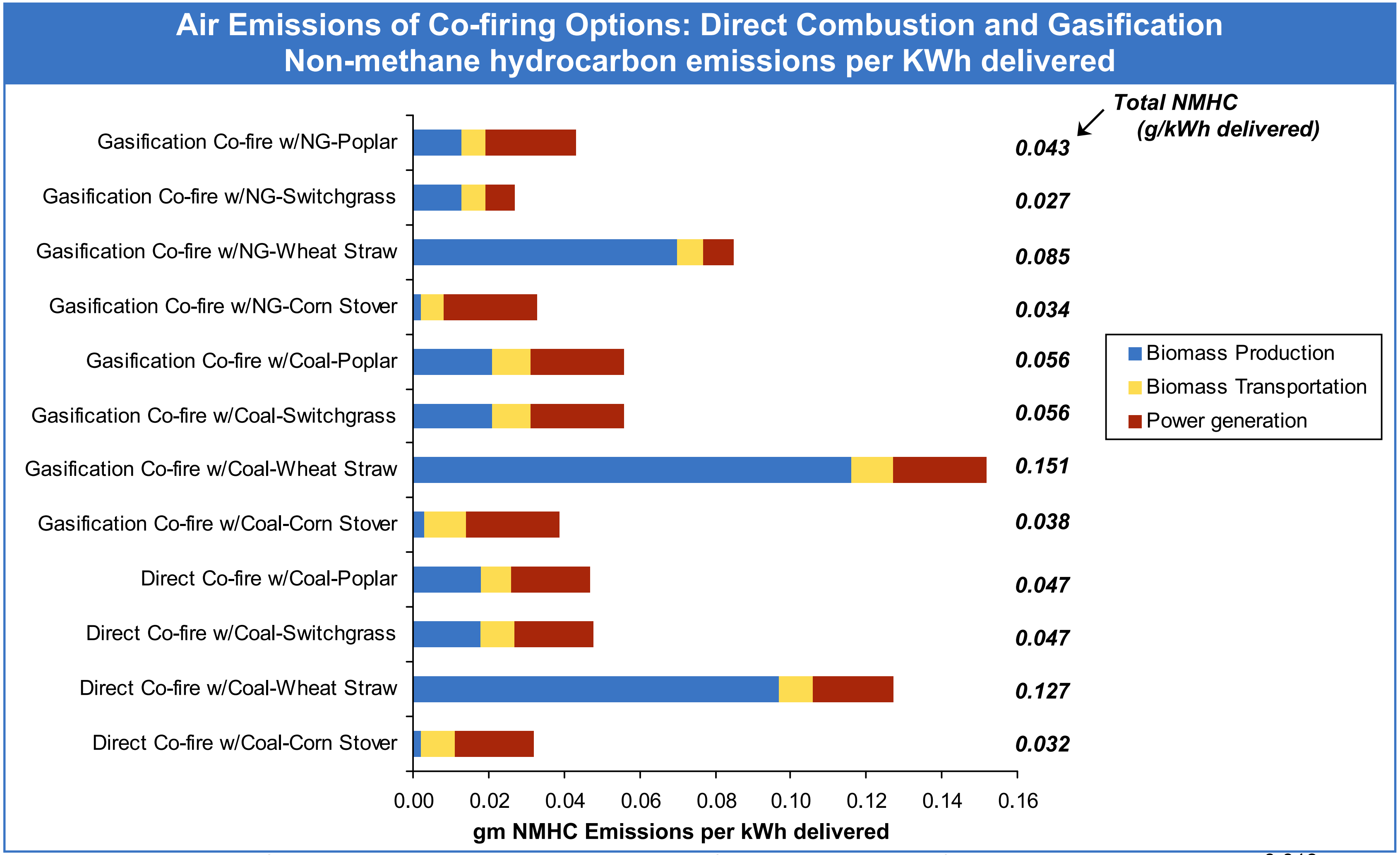


1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent. Emissions of a natural gas combined cycle plant 018 g/kWh. National electricity mix emissions 1.4 g/kWh. Emissions of a Coal fired plant 3.7 g/kWh

Air Emissions of Co-firing Options: Direct Combustion and Gasification
Methane emissions per KWh delivered

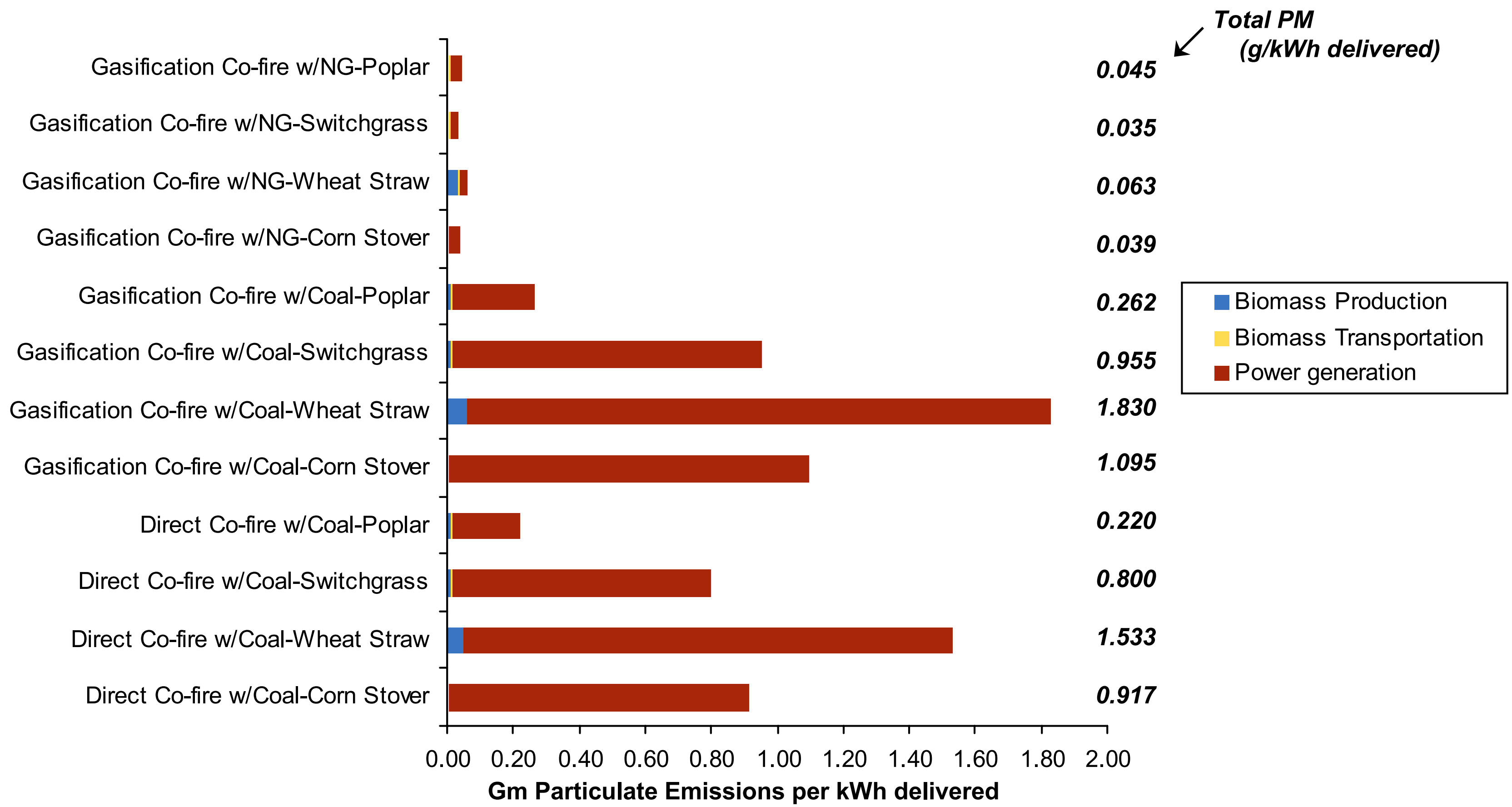


1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent. Emissions of a natural gas combined cycle plant .079 g/kWh. National electricity mix emissions 0.018 g/kWh. Emissions of a Coal fired plant 2.6 g/kWh



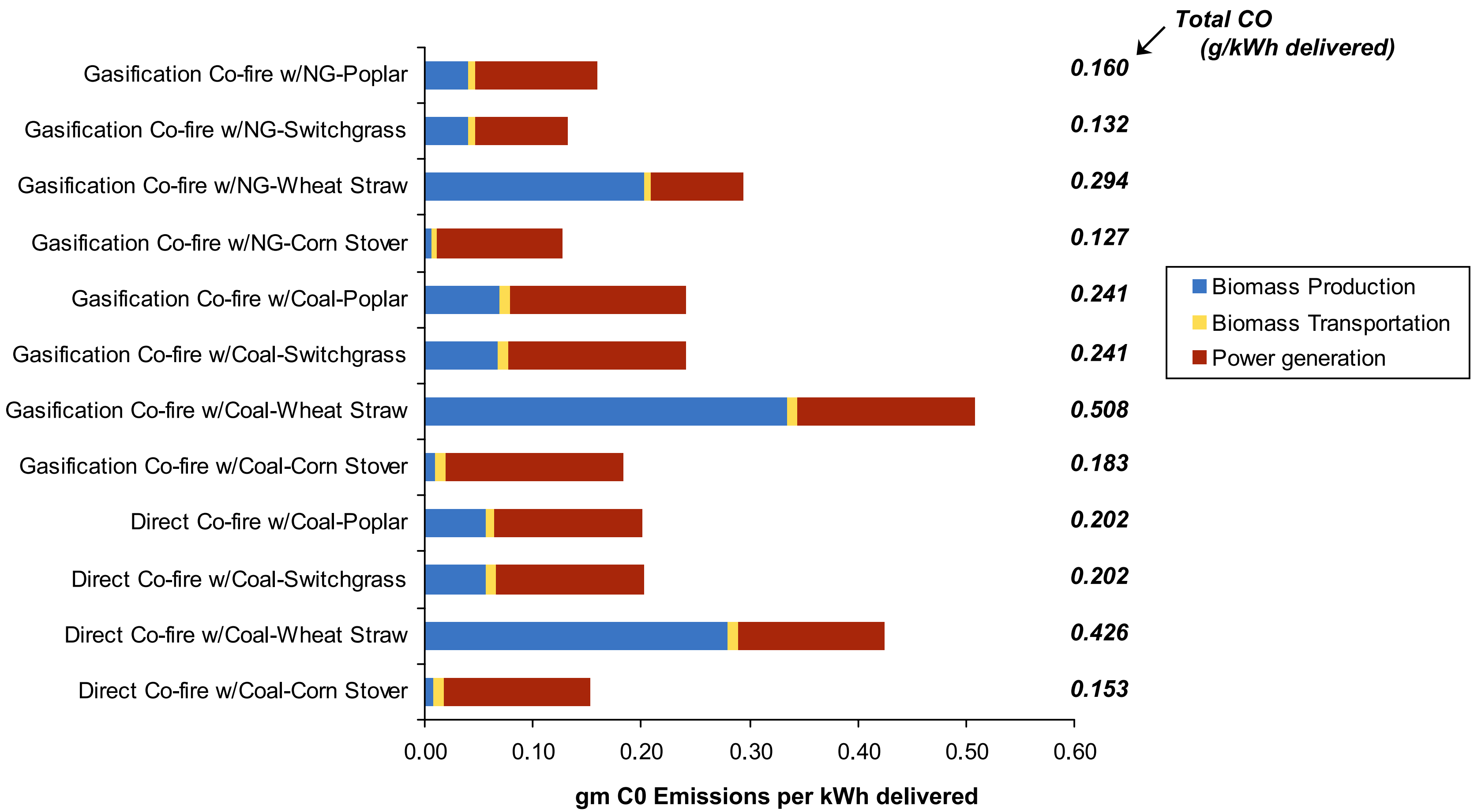
1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent. Emissions of a natural gas combined cycle plant 0.013 g/kWh. National electricity mix emissions 0.016 g/kWh. Emissions of a Coal fired plant 0.04 g/kWh

Air Emissions of Co-firing Options: Direct Combustion and Gasification
Particulate matter emissions per KWh delivered



1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent. Emissions of a natural gas combined cycle plant 0.023 g/kWh. National electricity mix emissions 0.084 g/kWh. Emissions of a Coal fired plant 1.1 g/kWh

Air Emissions of Co-firing Options: Direct Combustion and Gasification
Carbon monoxide emissions per KWh delivered

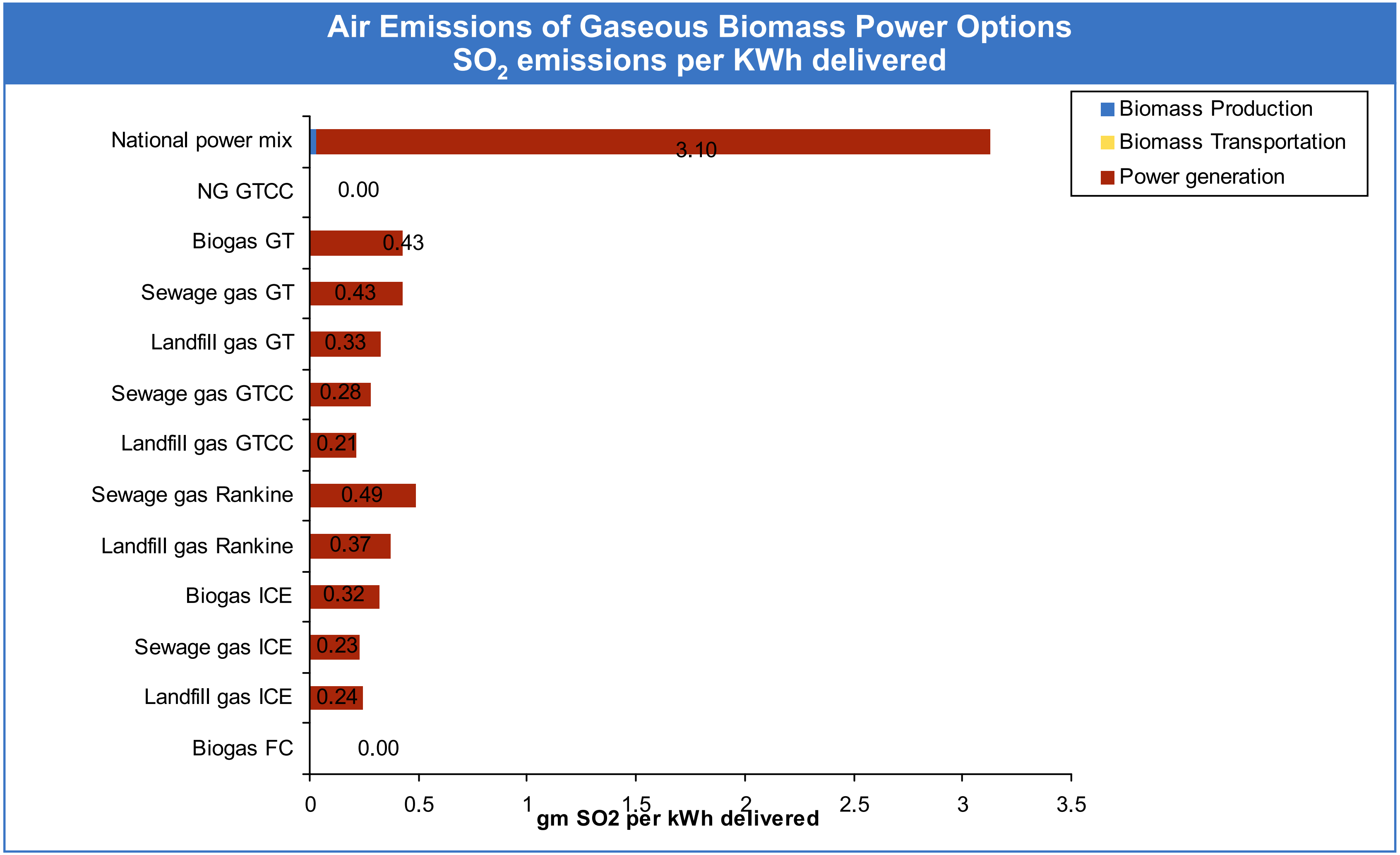


1. The shown emissions reflects transmission and distribution energy losses of 7.2 percent. Emissions of a natural gas combined cycle plant 0.086 g/kWh. National electricity mix emissions 0.12 g/kWh. Emissions of a Coal fired plant 0.14 g/kWh

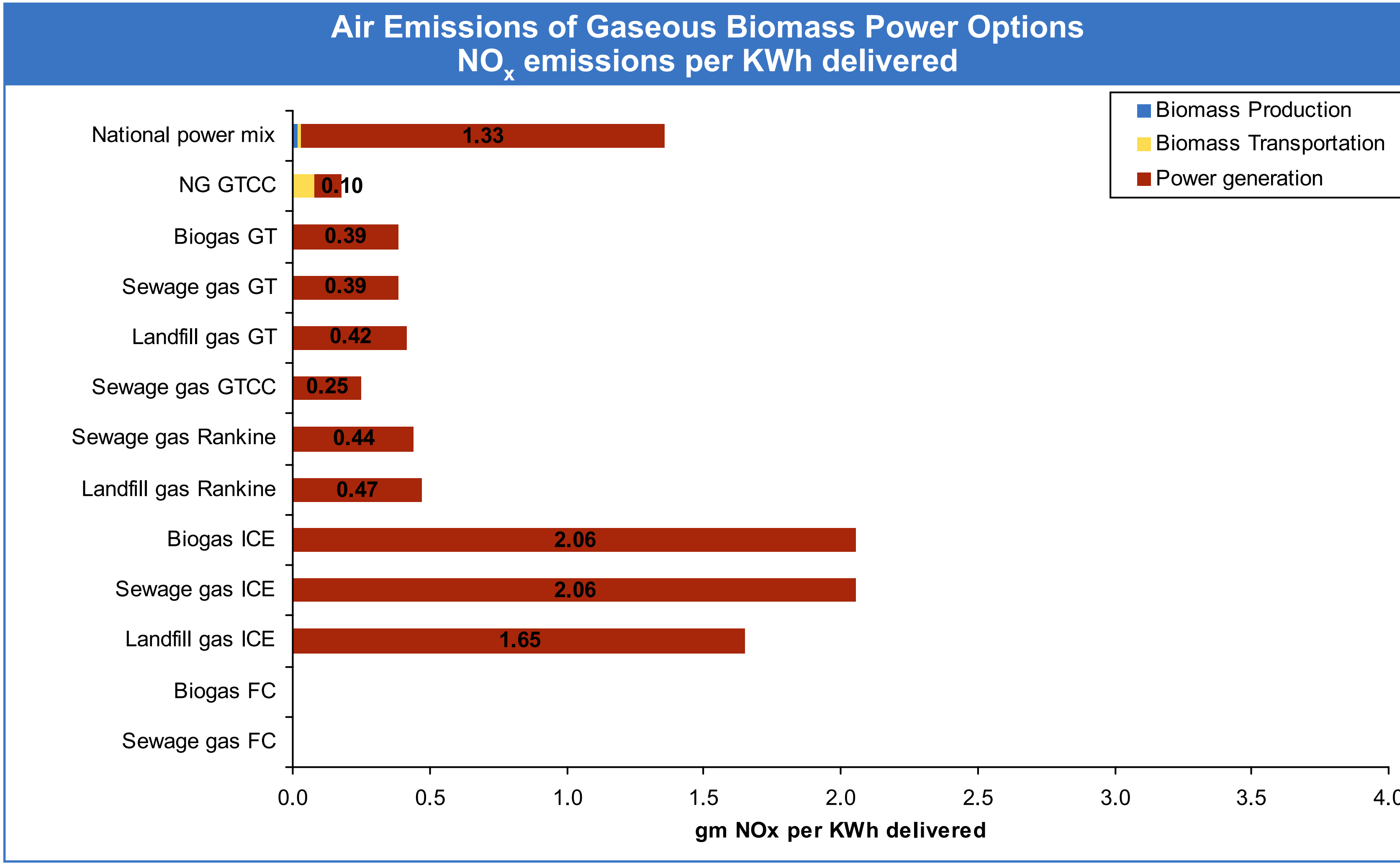
Gaseous biomass is generated and used onsite. Total carbon dioxide emissions are zero due to closed carbon cycle.

- Gaseous biomass is generated or produced on site
  - Landfill gas
  - Sewage gas
  - Digester gas
- Gaseous biomass is used onsite for power generation so there is no associated biomass transportation emissions
- Net carbon dioxide generated during electricity product is zero due to an overall closed carbon cycle

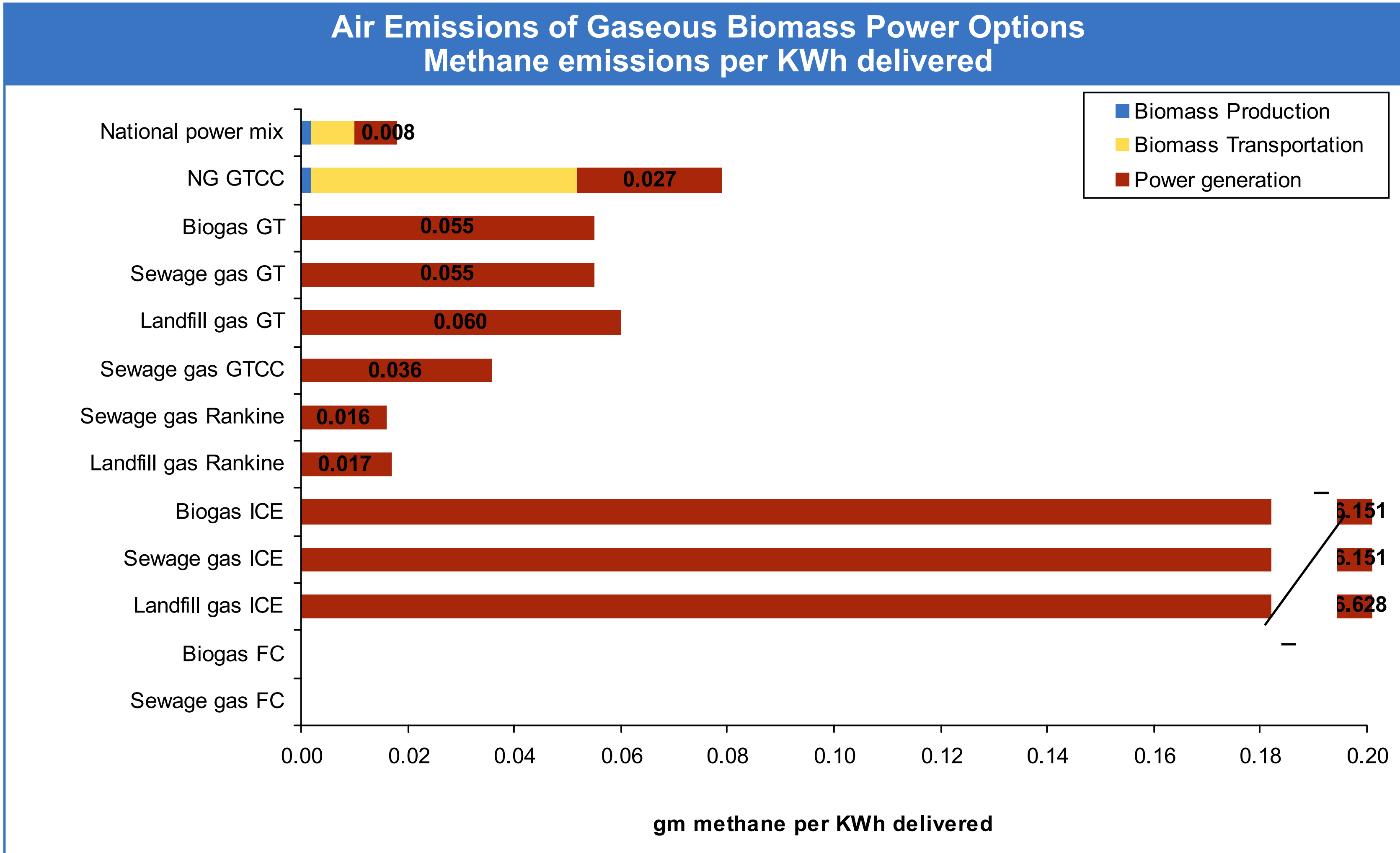
The low sulfur content of biomass result in low sulfur dioxide emissions.



NOx emissions for combustion of gaseous biomass is competitive for national electricity mix emissions but higher than natural gas GTCC.

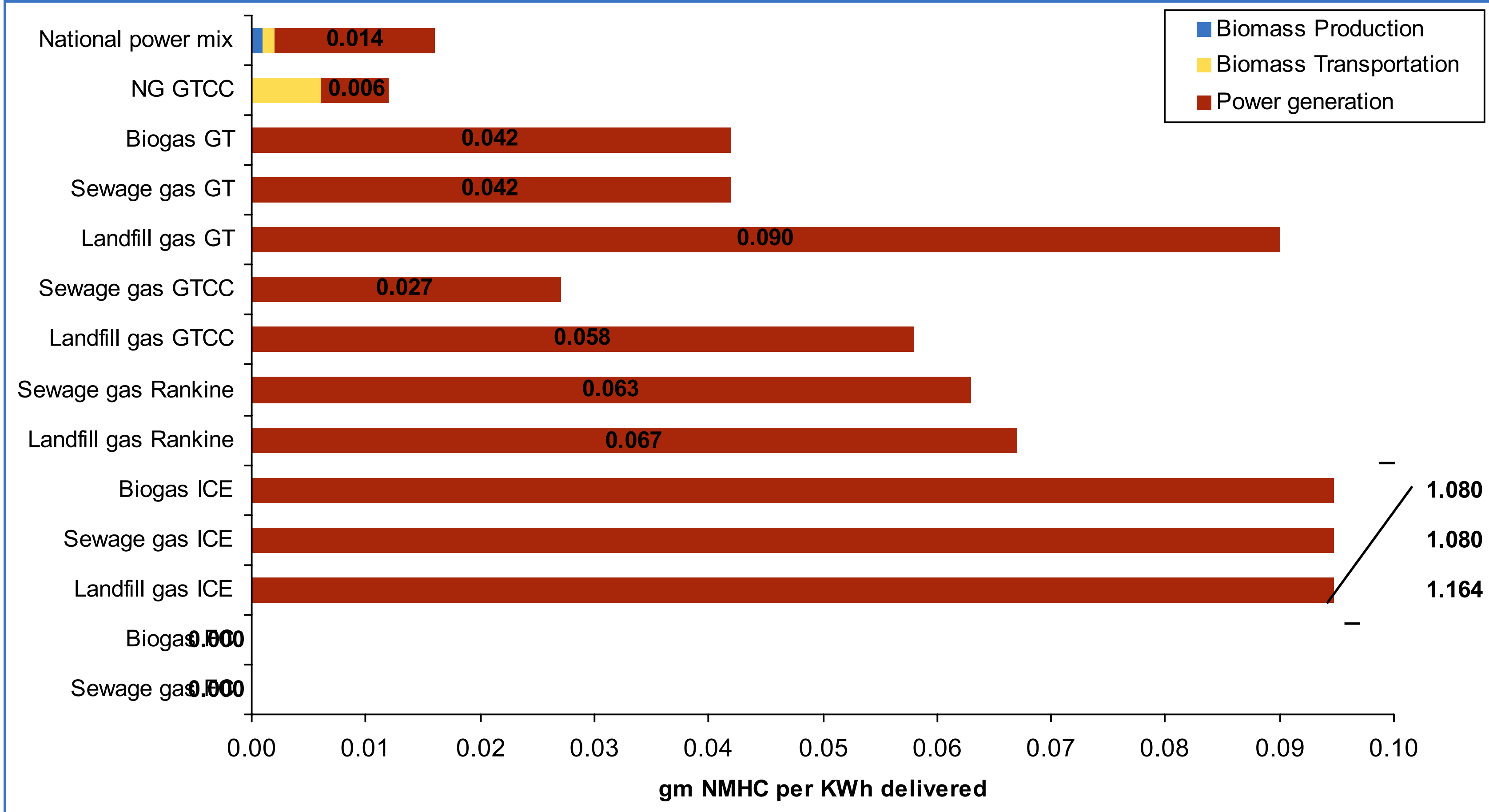


Methane emissions is an issue with gaseous biomass power options.

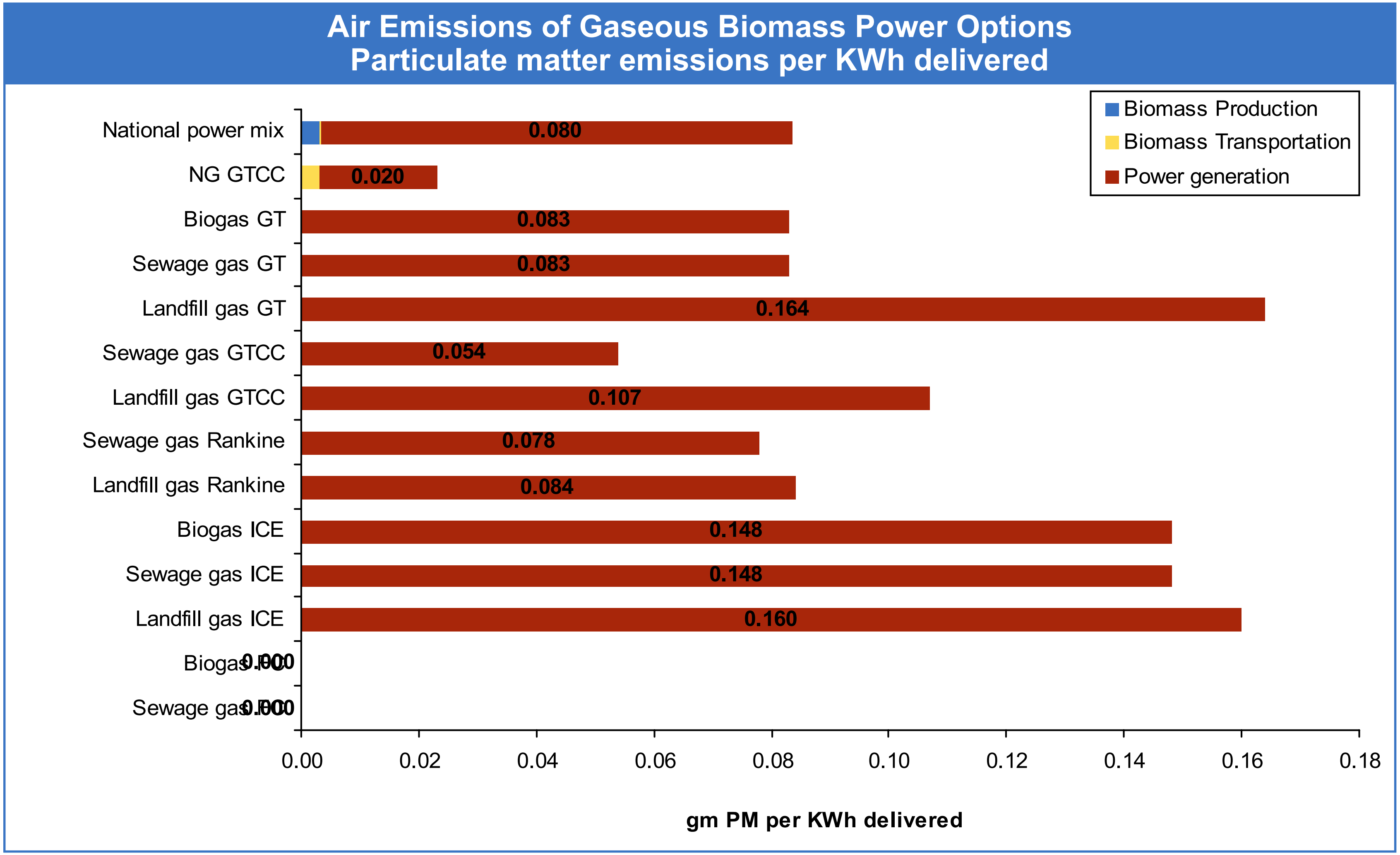


Biomass options do not provide an advantage in non-methane hydrocarbon emissions.

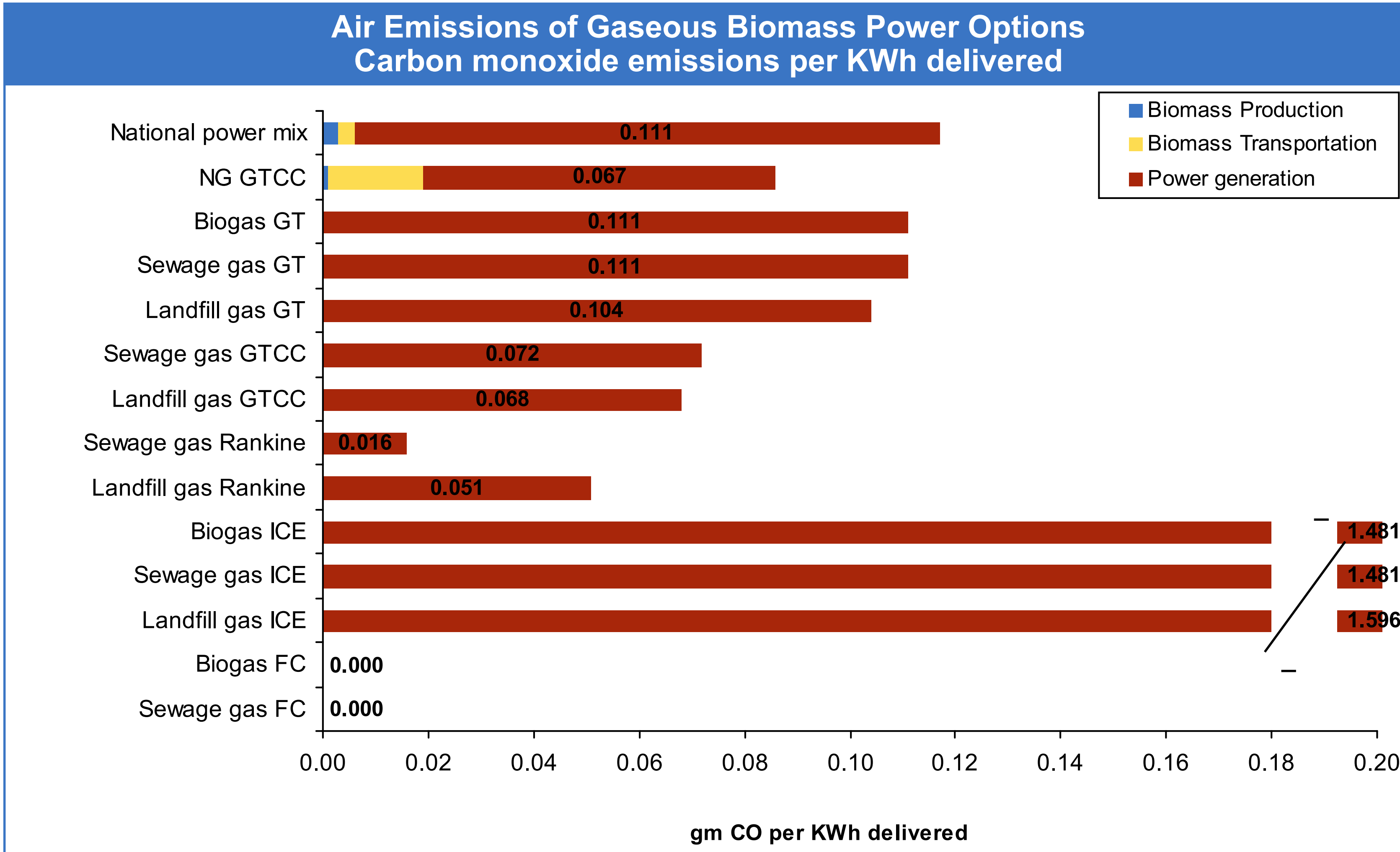
Air Emissions of Gaseous Biomass Power Options
Non-methane hydrocarbon emissions per KWh delivered



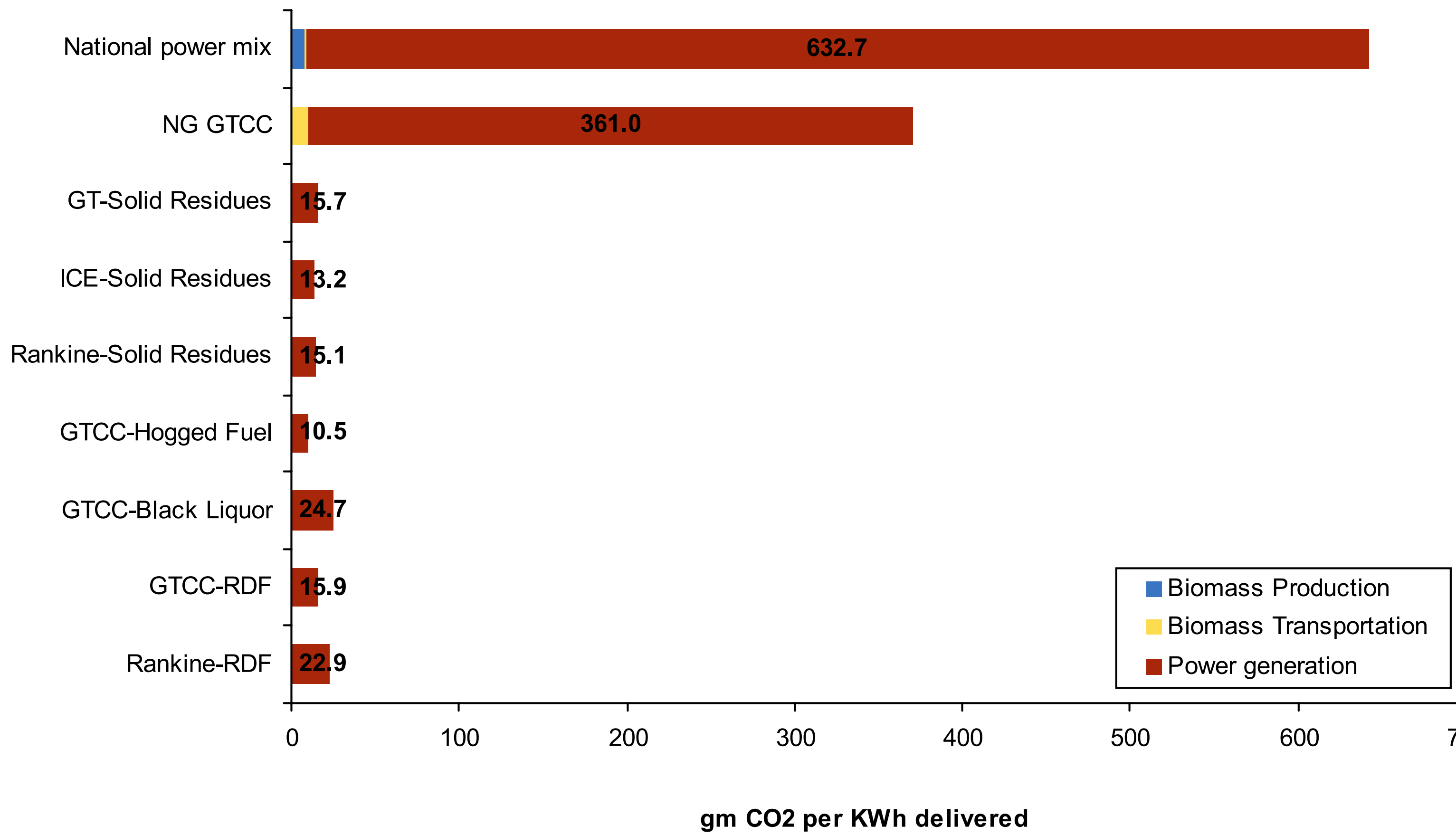
Particulate matter emissions are competitive to national electricity mix emissions for gaseous biomass combustion.

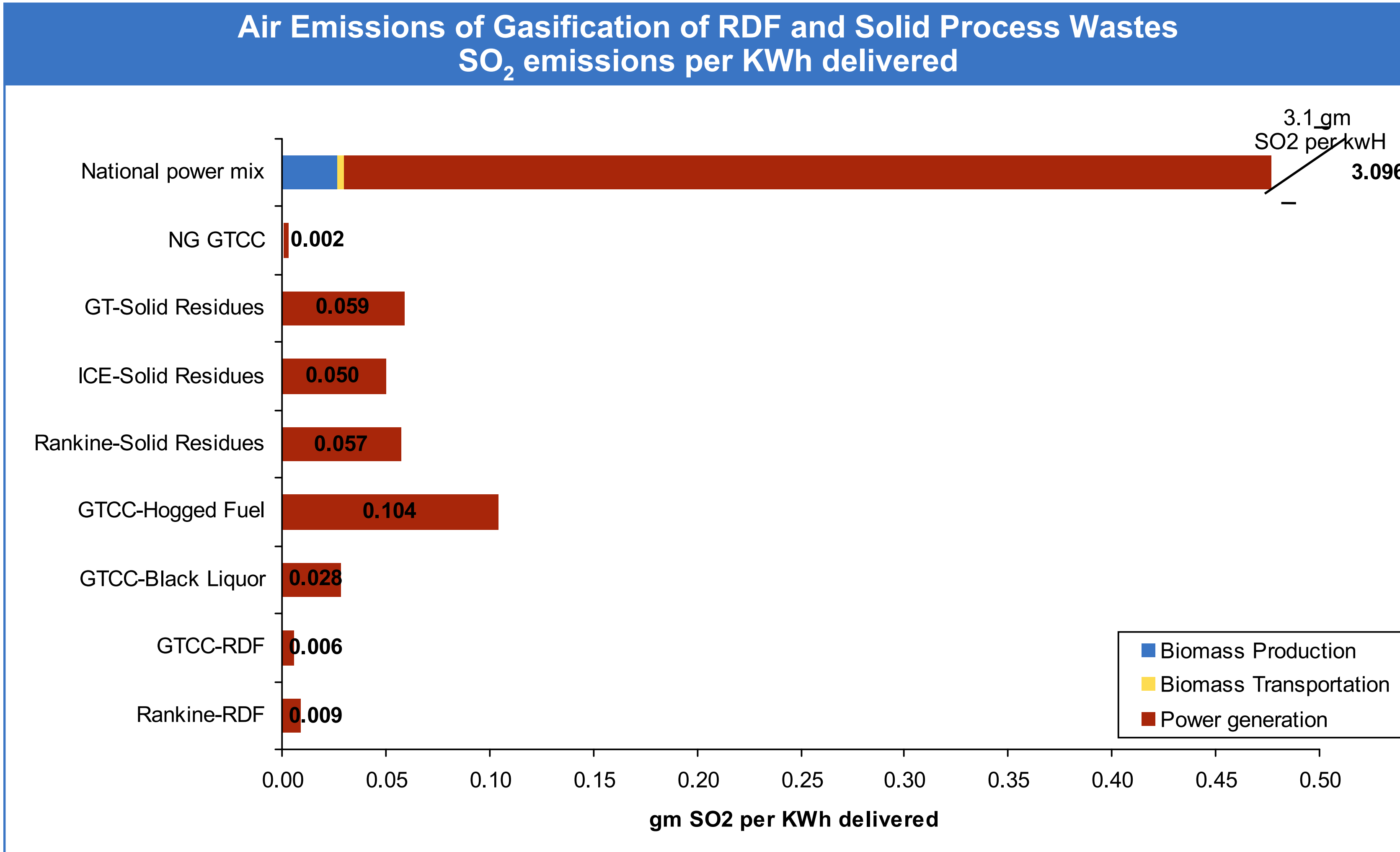


With the exception of ICE technology, gaseous biomass combustion options are within existing emissions from competitive technology.

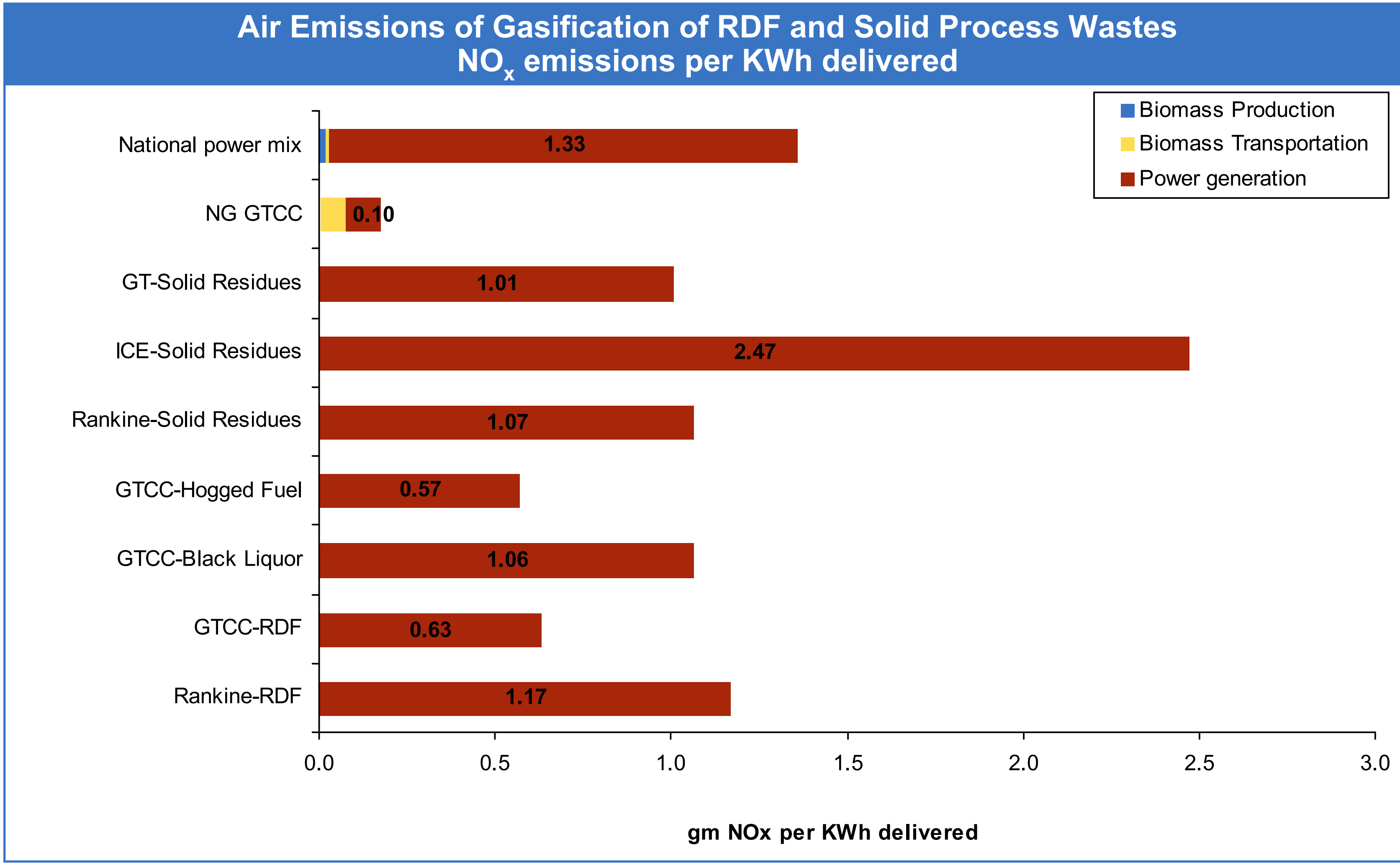


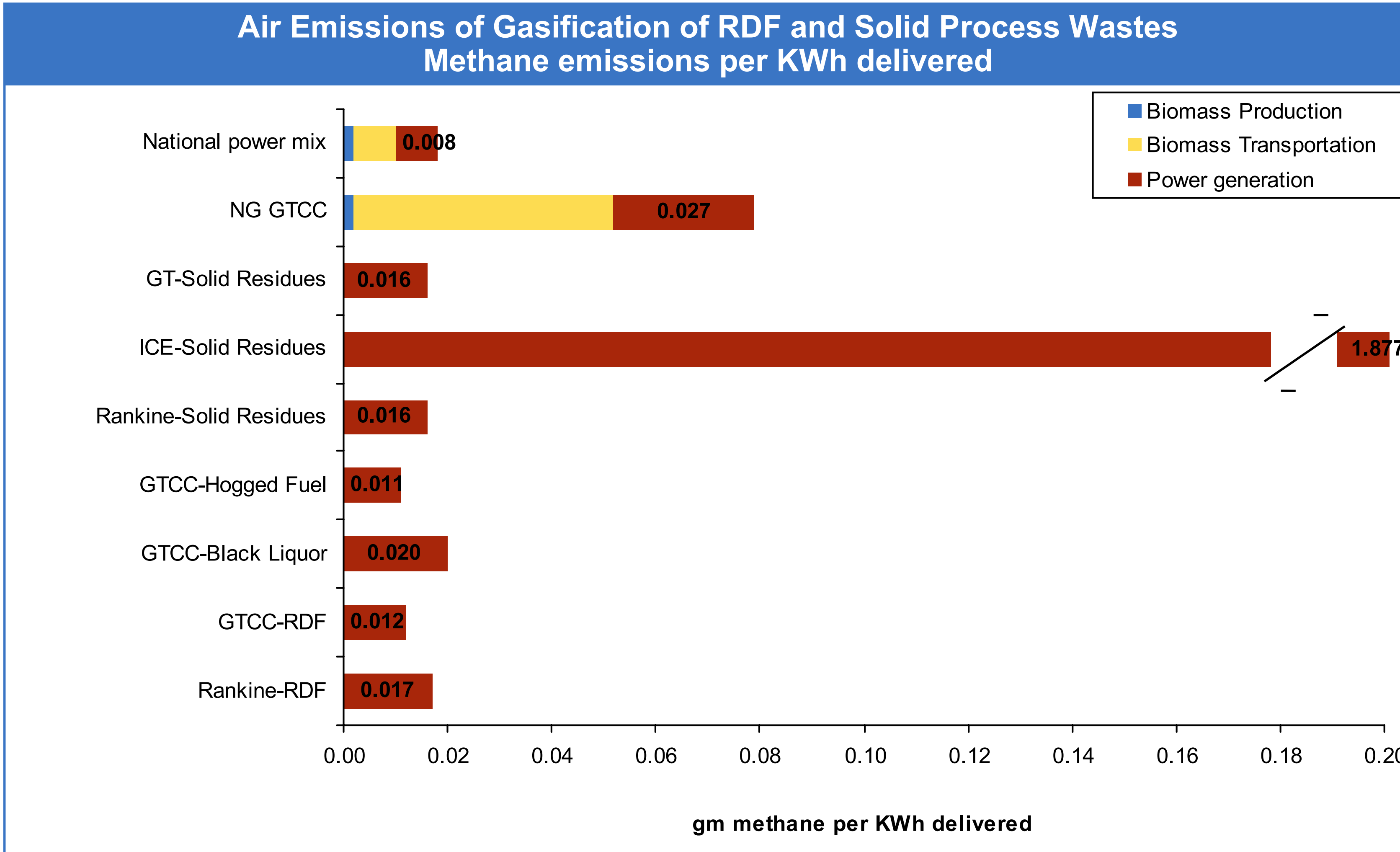
Air Emissions of Gasification of RDF and Solid Process Wastes
CO_2 emissions per KWh delivered

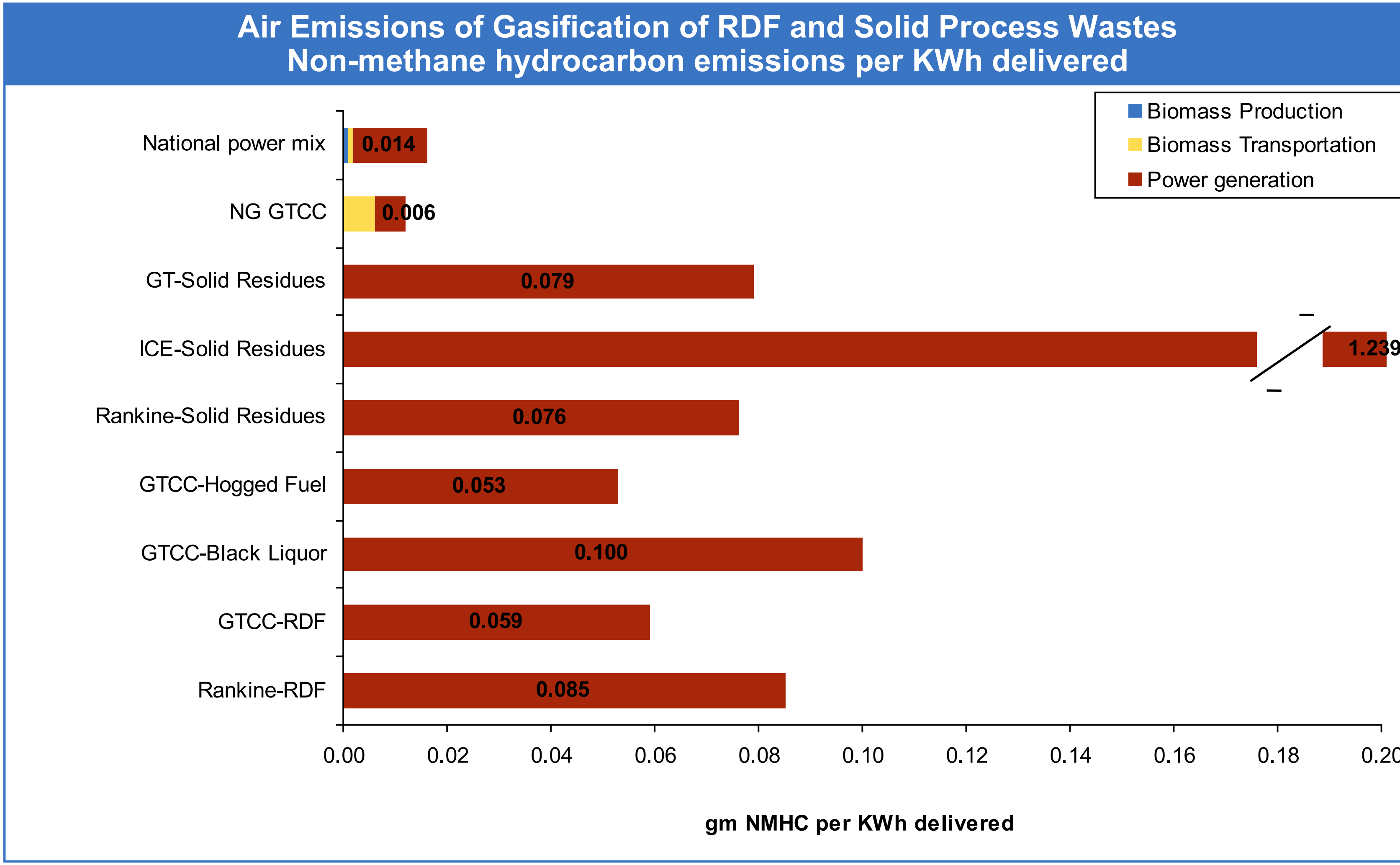


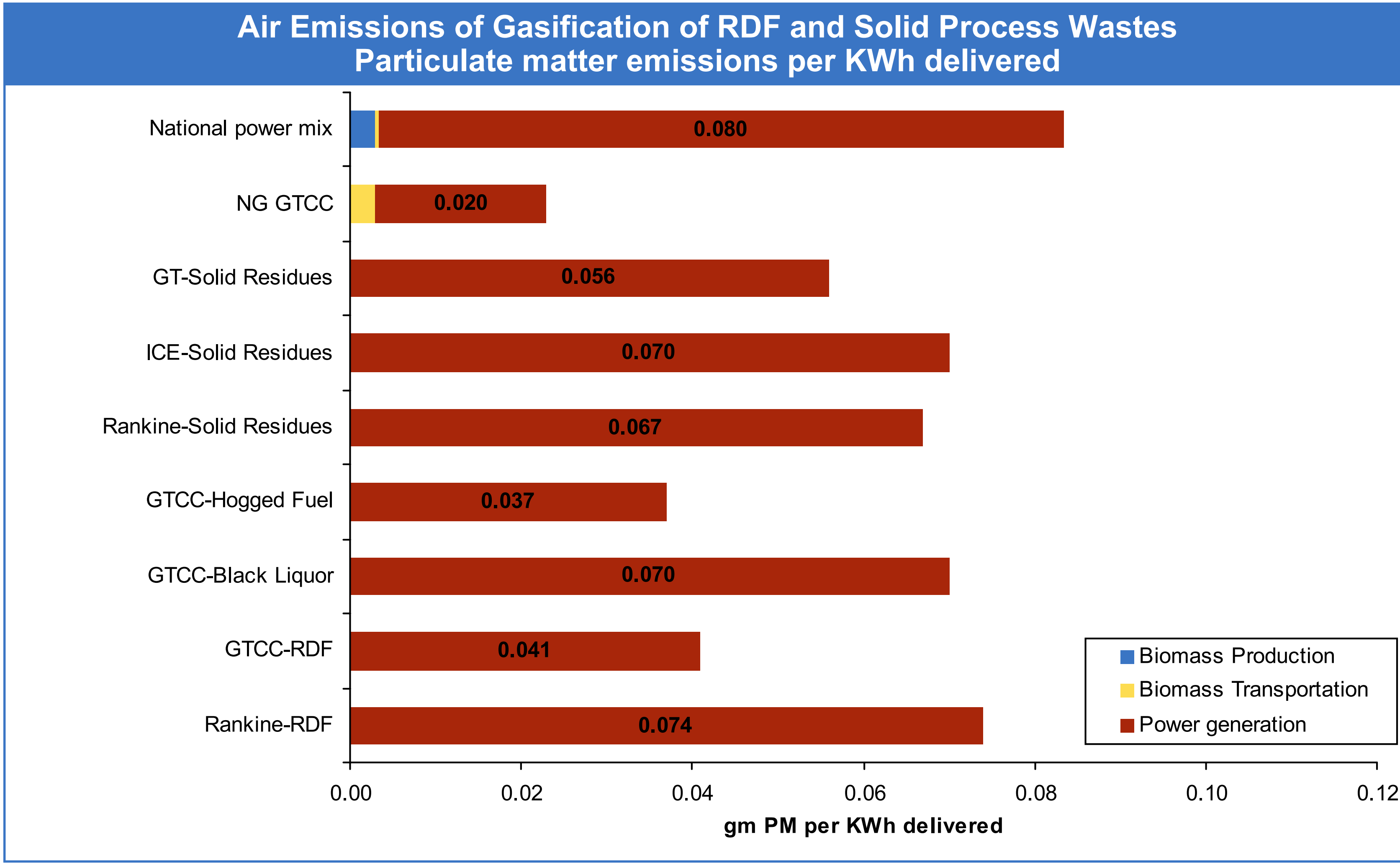


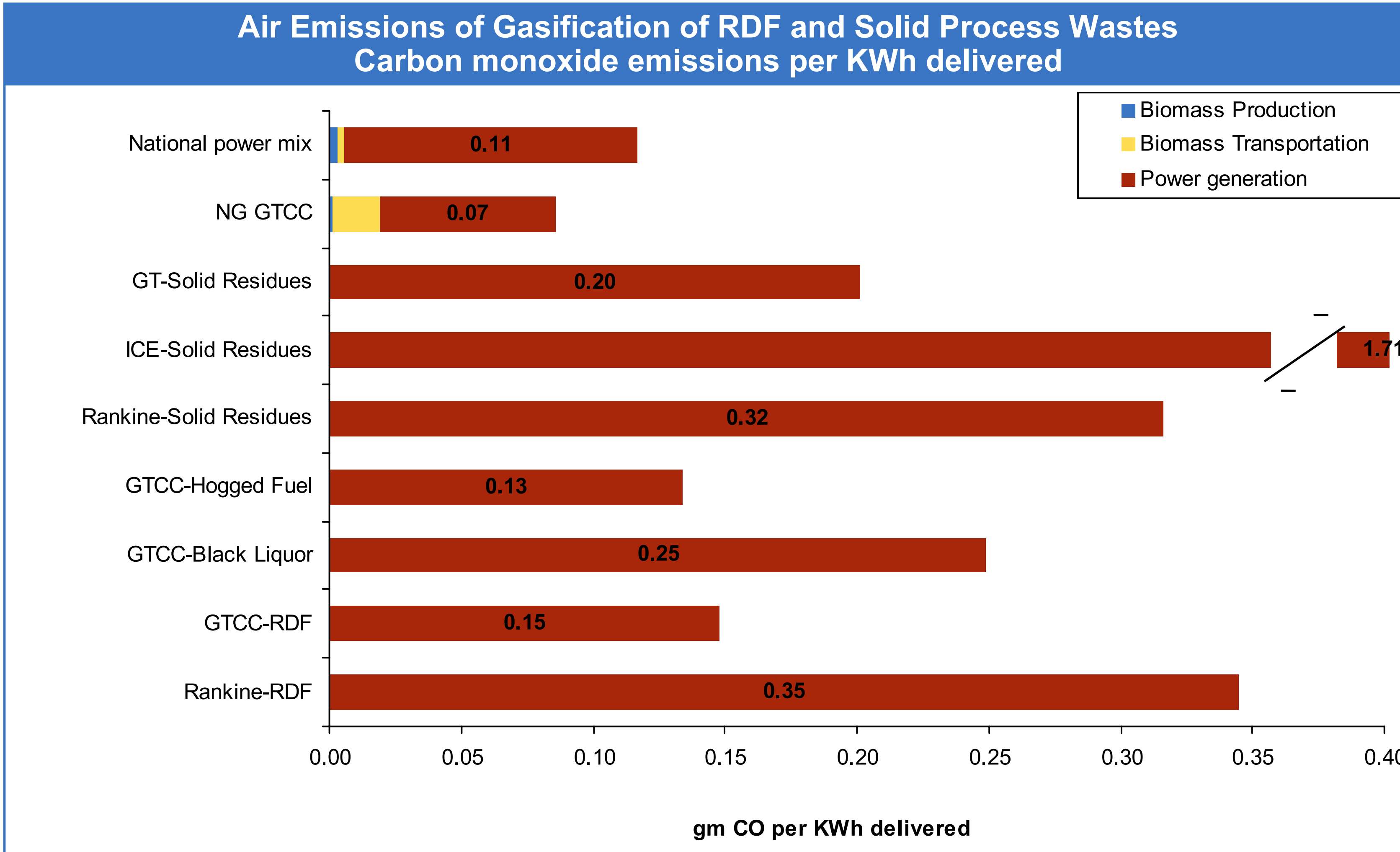
Air Emissions of Gasification of RDF and Solid Process Wastes
SO2 emissions per KWh delivered
3.1 gm
SO2 per kwH
National power mix
3.096
NG GTCC
0.002
GT-Solid Residues
0.059
ICE-Solid Residues
0.050
Rankine-Solid Residues
0.057
GTCC-Hogged Fuel
0.104
GTCC-Black Liquor
0.028
GTCC-RDF
0.006
Rankine-RDF
0.009
Biomass Production
Biomass Transportation
Power generation
0.00
0.05
0.10
0.15
0.20
0.25
0.30
0.35
0.40
0.45
0.50
gm SO2 per KWh delivered


Air Emissions of Gasification of RDF and Solid Process Wastes
NO_x emissions per KWh delivered
Biomass Production
Biomass Transportation
Power generation
National power mix
NG GTCC
GT-Solid Residues
ICE-Solid Residues
Rankine-Solid Residues
GTCC-Hogged Fuel
GTCC-Black Liquor
GTCC-RDF
Rankine-RDF
1.33
0.10
1.01
2.47
1.07
0.57
1.06
0.63
1.17
0.0
0.5
1.0
1.5
2.0
2.5
3.0
gm NOx per KWh delivered


Air Emissions of Gasification of RDF and Solid Process Wastes
Methane emissions per KWh delivered
Biomass Production
Biomass Transportation
Power generation
National power mix
NG GTCC
GT-Solid Residues
ICE-Solid Residues
Rankine-Solid Residues
GTCC-Hogged Fuel
GTCC-Black Liquor
GTCC-RDF
Rankine-RDF
0.008
0.027
0.016
1.877
0.016
0.011
0.020
0.012
0.017
0.00
0.02
0.04
0.06
0.08
0.10
0.12
0.14
0.16
0.18
0.20
gm methane per KWh delivered

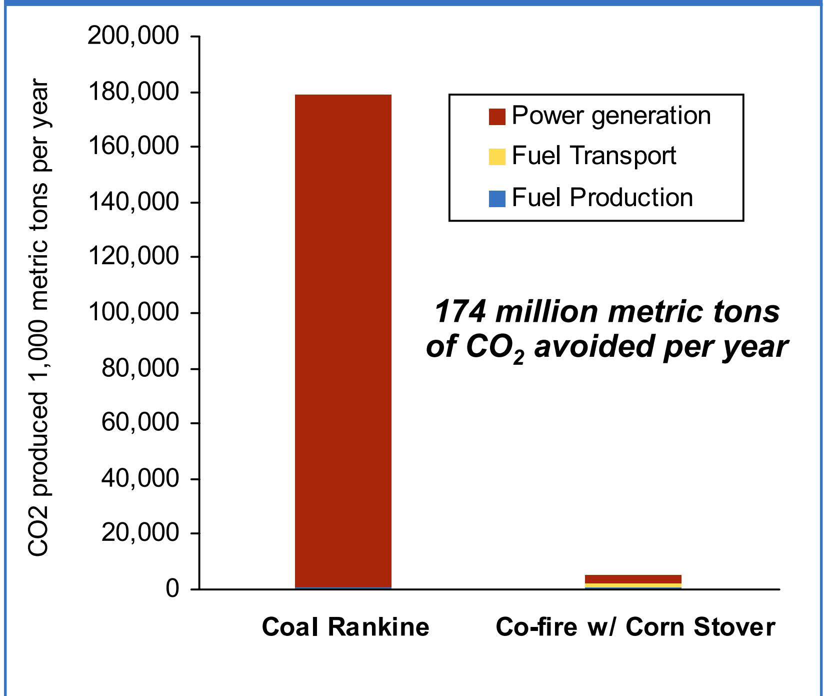

Air Emissions of Gasification of RDF and Solid Process Wastes
Non-methane hydrocarbon emissions per KWh delivered
Biomass Production
Biomass Transportation
Power generation
National power mix
NG GTCC
GT-Solid Residues
ICE-Solid Residues
Rankine-Solid Residues
GTCC-Hogged Fuel
GTCC-Black Liquor
GTCC-RDF
Rankine-RDF
0.014
0.006
0.079
1.239
0.076
0.053
0.100
0.059
0.085
0.00
0.02
0.04
0.06
0.08
0.10
0.12
0.14
0.16
0.18
0.20
gm NMHC per KWh delivered


Air Emissions of Gasification of RDF and Solid Process Wastes
Particulate matter emissions per KWh delivered
National power mix
NG GTCC
GT-Solid Residues
ICE-Solid Residues
Rankine-Solid Residues
GTCC-Hogged Fuel
GTCC-Black Liquor
GTCC-RDF
Rankine-RDF
0.080
0.020
0.056
0.070
0.067
0.037
0.070
0.041
0.074
0.00
0.02
0.04
0.06
0.08
0.10
0.12
gm PM per KWh delivered
Biomass Production
Biomass Transportation
Power generation

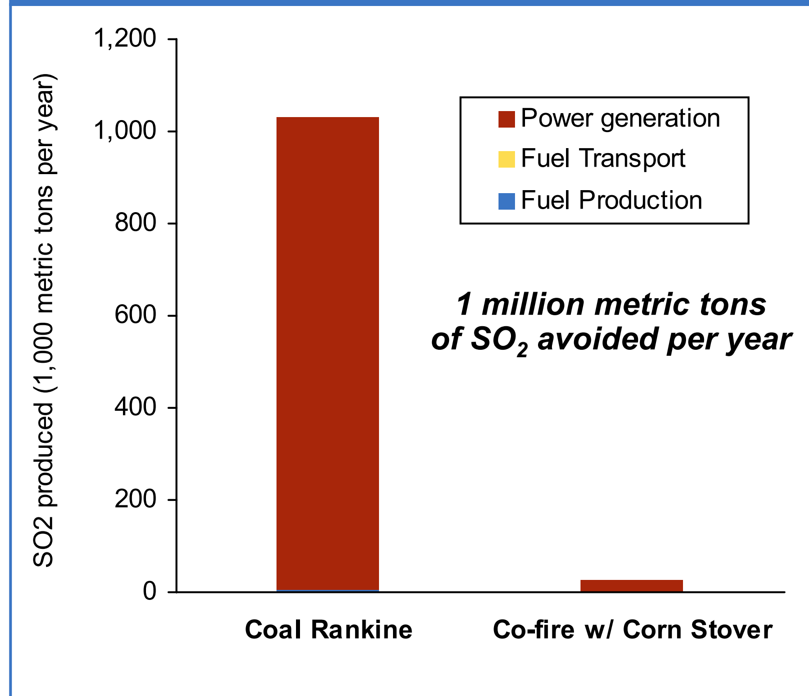

Air Emissions of Gasification of RDF and Solid Process Wastes
Carbon monoxide emissions per KWh delivered
Biomass Production
Biomass Transportation
Power generation
National power mix
NG GTCC
GT-Solid Residues
ICE-Solid Residues
Rankine-Solid Residues
GTCC-Hogged Fuel
GTCC-Black Liquor
GTCC-RDF
Rankine-RDF
0.11
0.07
0.20
1.71
0.32
0.13
0.25
0.15
0.35
0.00
0.05
0.10
0.15
0.20
0.25
0.30
0.35
0.40
gm CO per KWh delivered

At high levels of market penetration, biomass co-firing produces significant CO_2 and SO_2 reductions. Moreover, the total investment cost for CO_2 reductions is estimated to be a modest $40/ton.

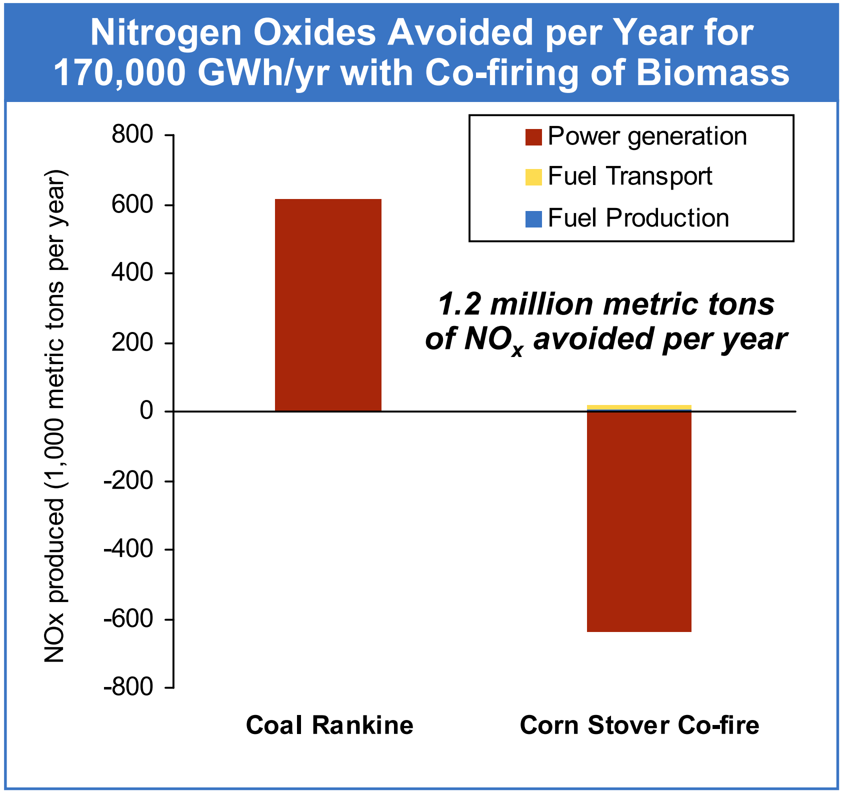
Carbon Dioxide Avoided per Year for 170,000 GWh/yr with Co-firing of Biomass



Sulfur Dioxide Avoided per Year for 170,000 GWh/yr with Co-firing of Biomass



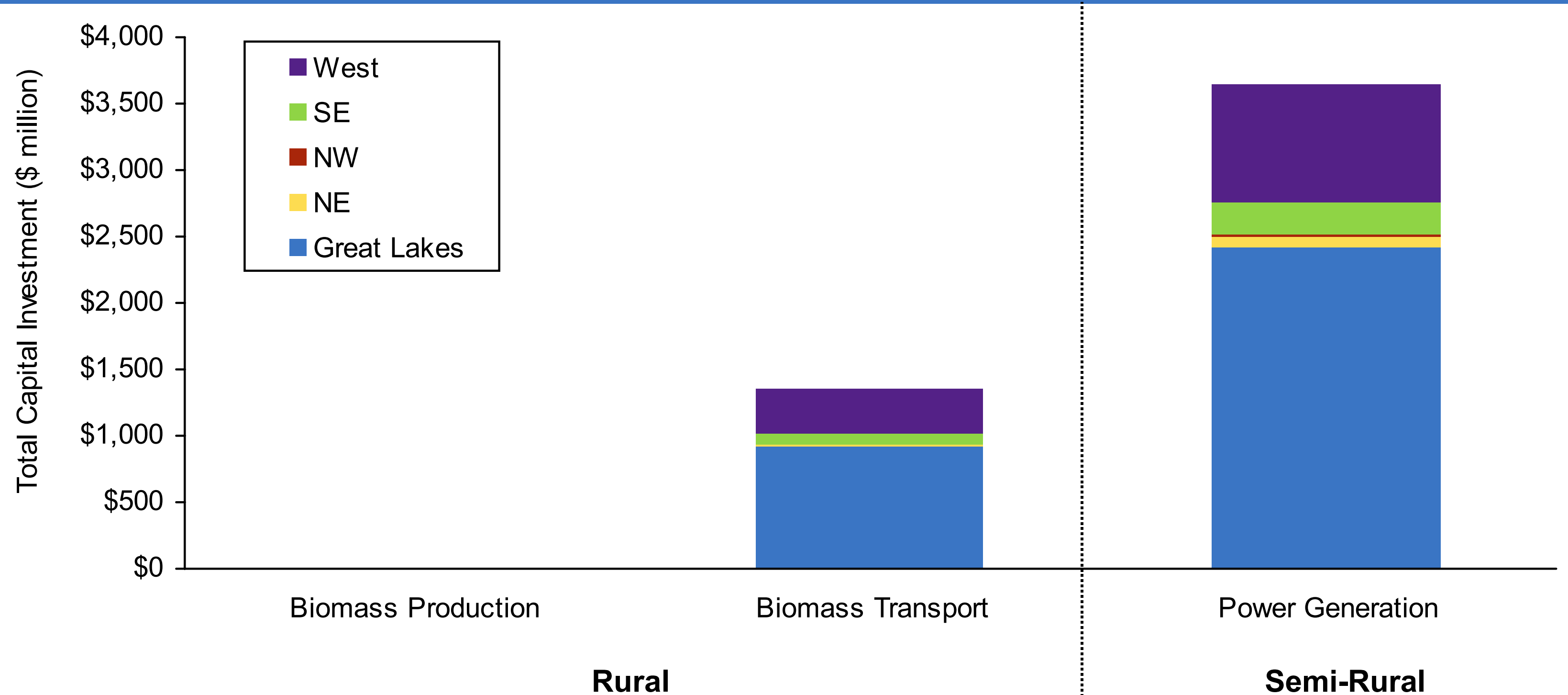
Co-firing has the potential to achieve significant NOx reductions because emissions are reduced for the entire coal plant, not just the biomass fraction.



At the high level of market penetration shown here (roughly 10% of current coal-fired power generation), approximately 20% of total power sector NOx emissions are eliminated.

The bulk of the capital investment for implementing corn stover co-firing with coal may occur at the power plants themselves.

Maximum Total Capital Investment for Direct Corn Stover Co-firing in Coal Plants ($ million)

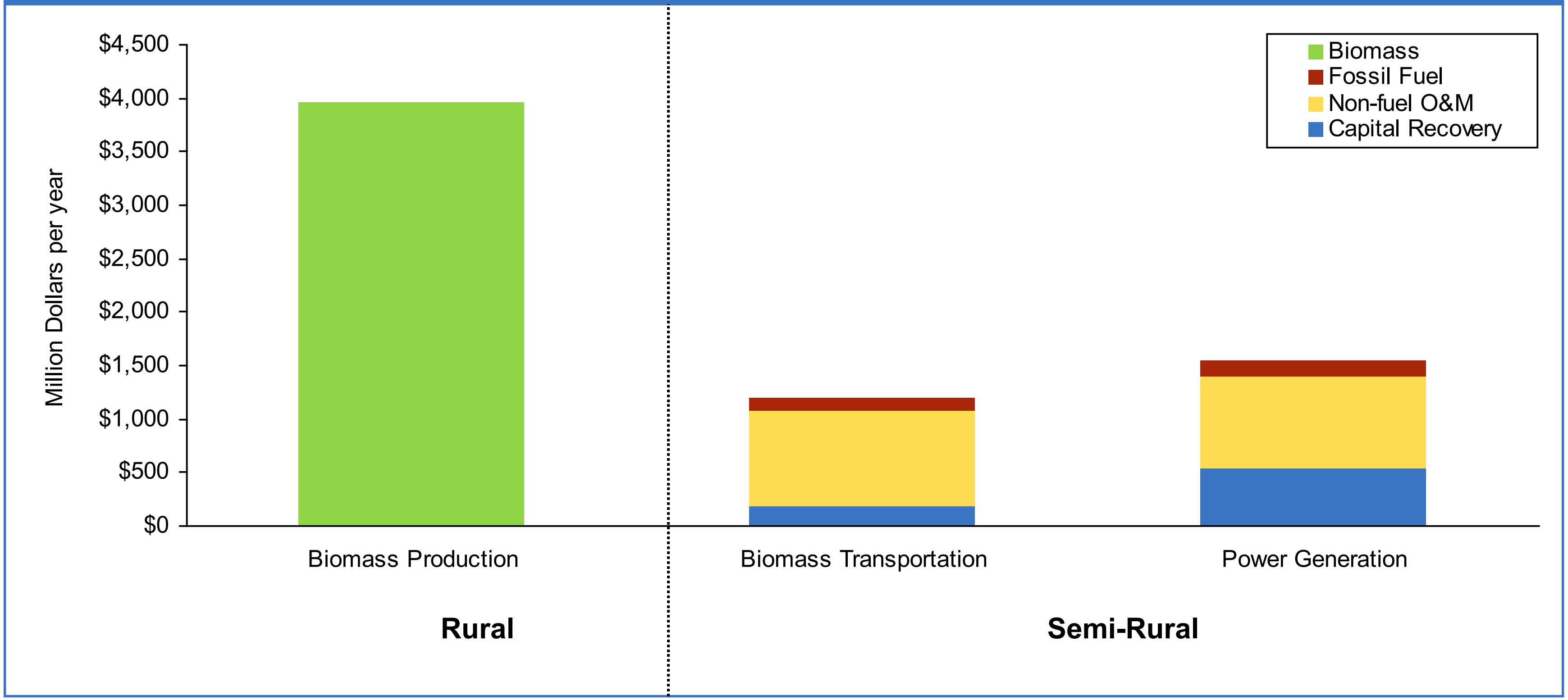


The investments shown produce a total of 170,000 GWh of electricity per year using a total of 132 million tons per year of corn stover for direct coal co-firing.

The capital investment associated with biomass production is assumed to be contained in the feedstock price.

For biomass co-firing, the single largest annual operating cost item is expected to be the biomass fuel itself.

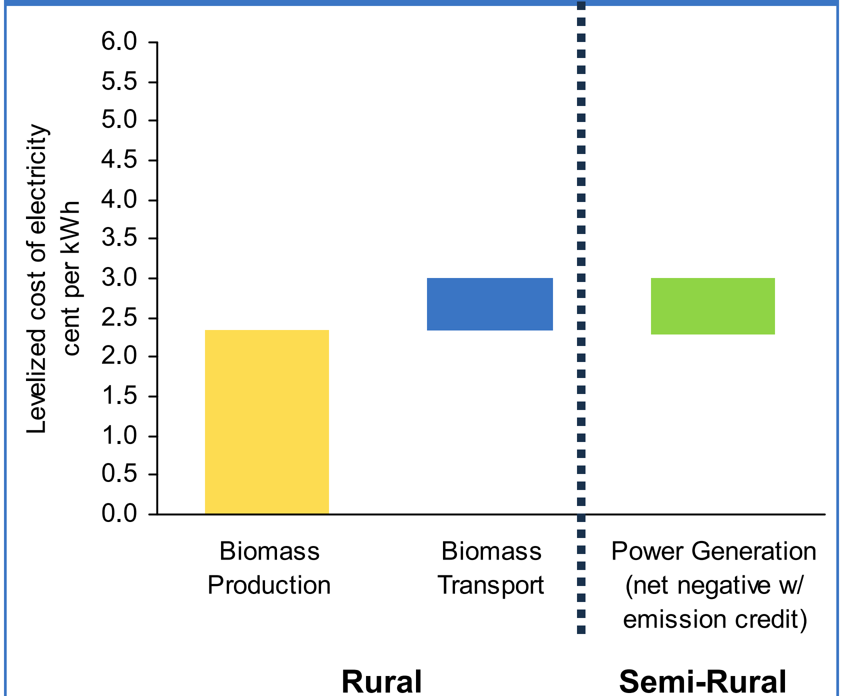
Direct Corn Stover Co-firing in Coal Plants – Maximum Annual Expenditures ($ million per year)



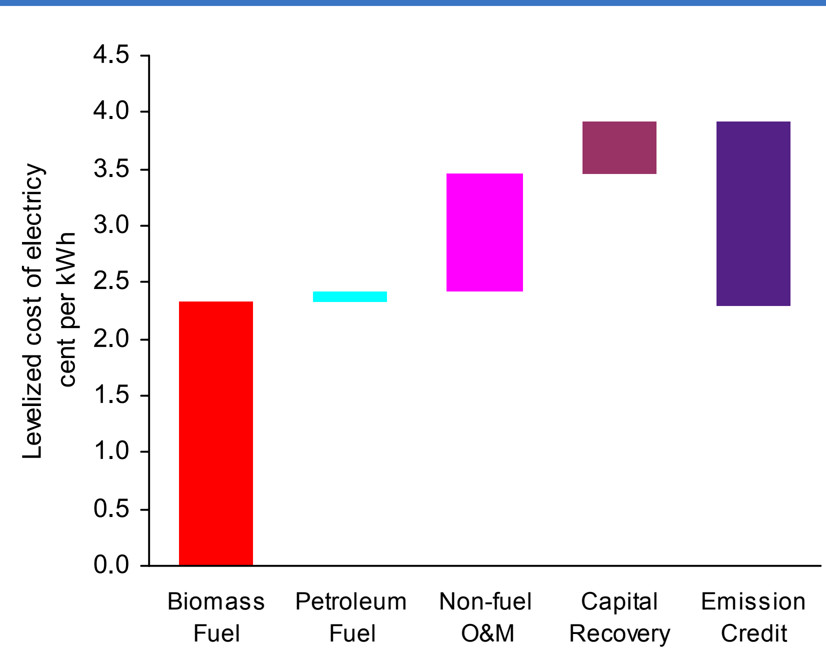
1. Capital recovery assumptions are 13% per year for biomass transport investments and 15% for power plant investments.
2. The feedstock cost of corn stover is assumed to be $30 per ton (dry basis). The capital and operating costs of biomass production are incorporated into this price.
3. The investments shown produce a total of 170,000 GWh of electricity per year using a total of 132 million tons per year of corn stover co-firing with coal.

Value creation for electricity generation is primarily in the biomass fuel; emission credits could cover the cost of nonfuel O&M and capital recovery.

Corn Stover Direct Co-Firing With Coal Levelized Cost of Electricity, cent per kWh



Corn Stover Direct Co-Firing With Coal Levelized Cost of Electricity, cent per kWh

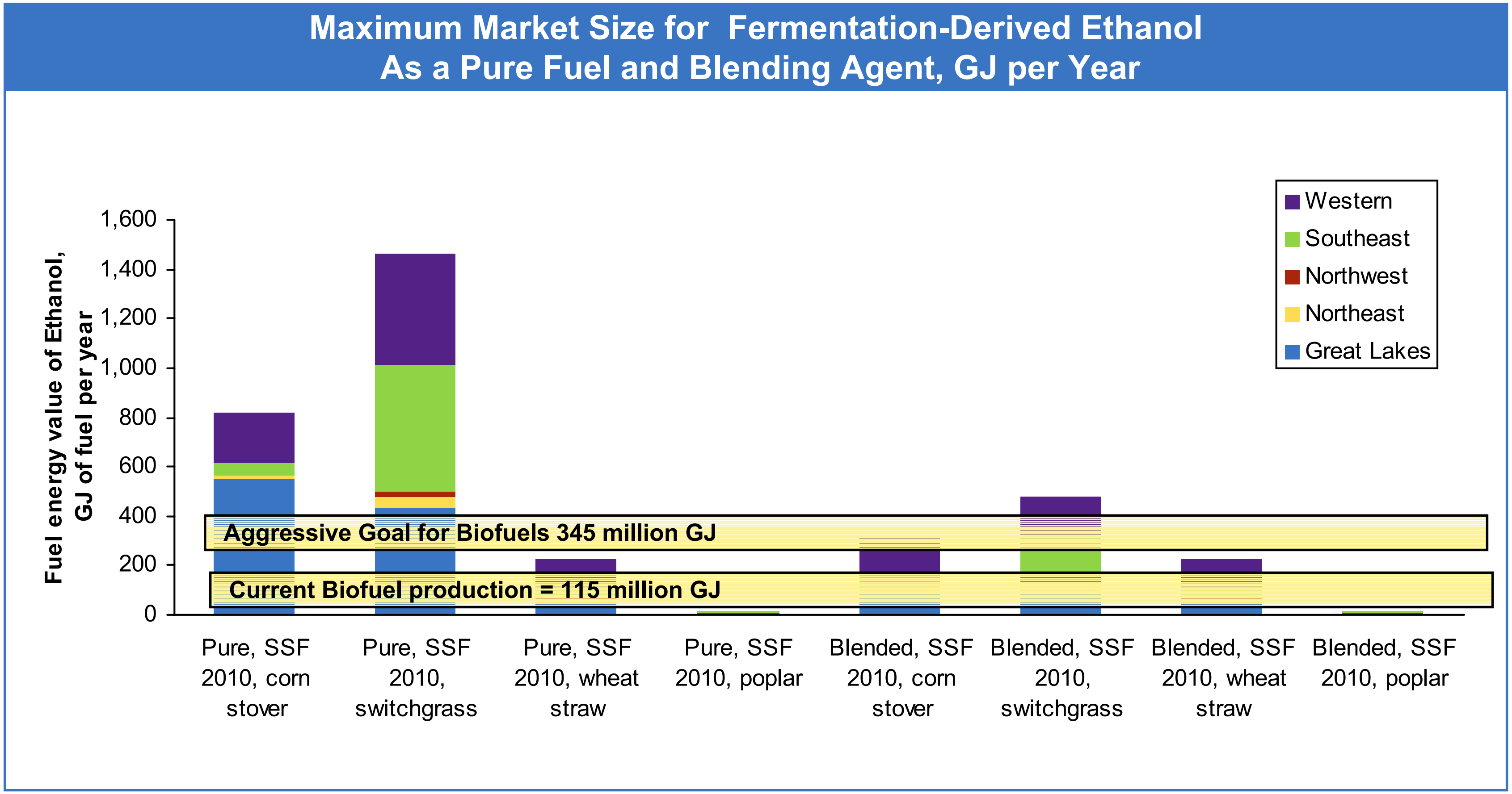


1. Capital recovery cost per year are a 13% per year for biomass transport investment and 15% for power generation investment. The capital recovery for biomass production is included in the price for biomass.
2. The fuel operating cost for biomass production is solely the cost of the biomass. The capital, non-fuel operating, and petroleum fuel costs in biomass production are incorporated into the price for biomass
3. The feedstock cost of corn stover is $30 per ton.

The following fuel options have been retained for further analysis of benefits and impacts.

Ethanol	• This fuel appears to represent the optimal mix of cost-competitiveness, technical viability and market potential • Careful consideration needs to be given to feedstock selection, particularly as the herbaceous crops will not always have sufficient lignin for on-site power generation • Mixed alcohol fuels might be added once the technology is sufficiently proven • Most likely near term continued application is for a blending agent which commands premium value over that just based on energy content
FT Diesel	• FT-diesel provides a replacement option for petroleum derived diesel: – FT diesel is sulfur-free and aromatic free and can be used to help meet new diesel specs – It can be used with the existing petroleum infrastructure without any modifications – FT diesel from biomass must compete with GTL FT diesel, which is expected to be fully cost-competitive with petroleum diesel

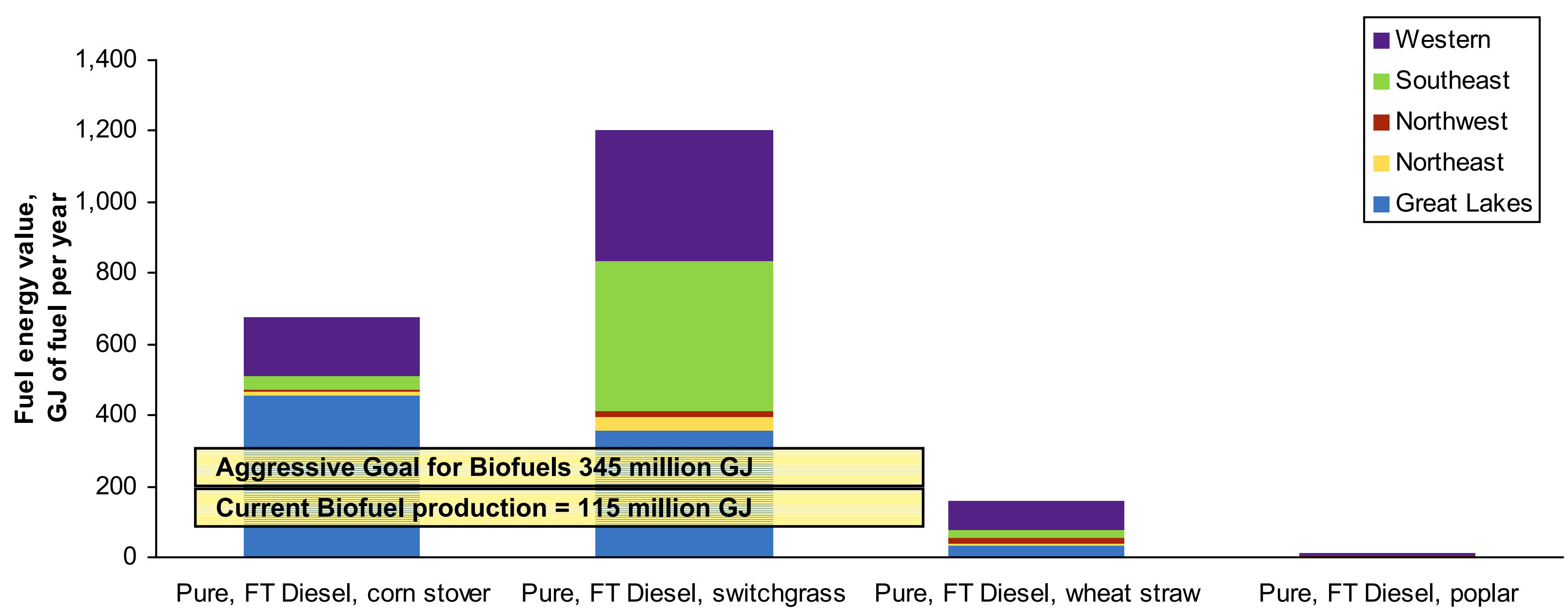
The maximum market for blended fuels is largely demand limited, not resource limited.



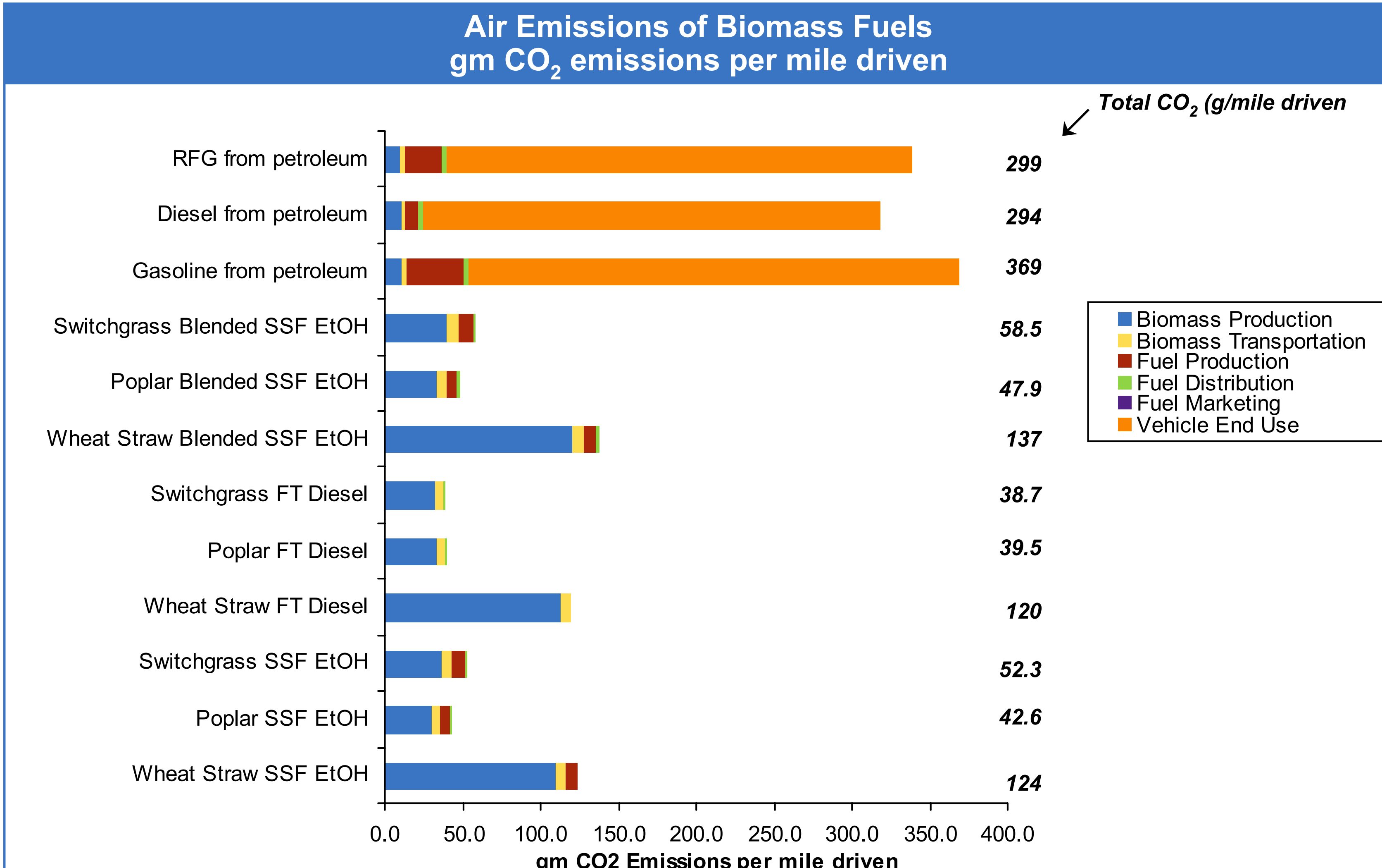
1. The bars represent using the entire resource to generate fuel.
2 Ethanol fuel blends are on a volume basis at 10 percent.
3. The following energy values have been used for the fuels: Ethanol 88.6 MJ per gal.; DME 80.4 MJ per gal; FT Diesel 138.4 MJ per gal.
4. Blended ethanol using corn stover and switch grass are demand limited in the Great Lakes and Western Regions.
5. Blended ethanol using switch grass is also demand limited in the Southeast region.

The high process efficiency of DME and the large potential resource of switchgrass represent a large opportunity for biofuels.

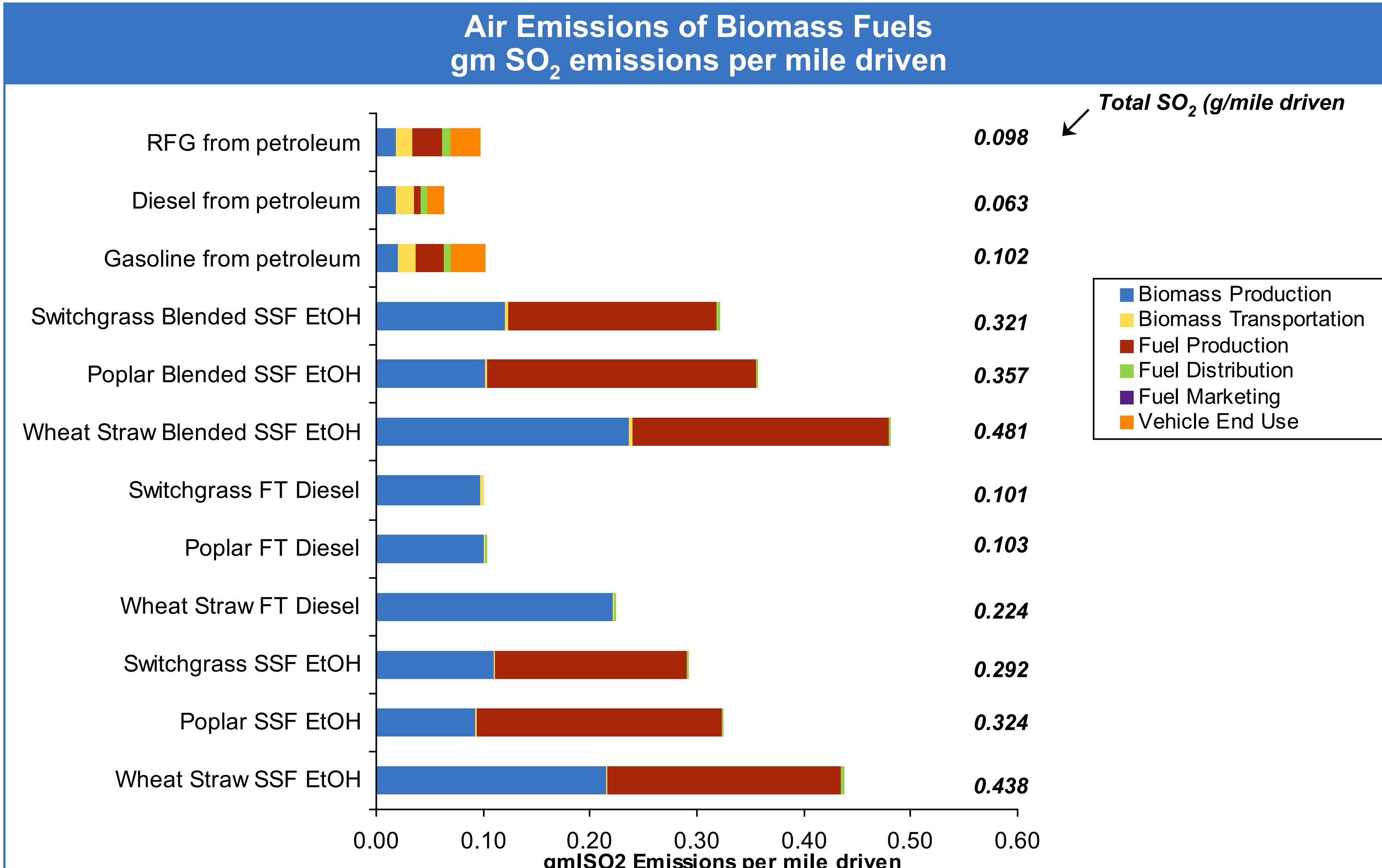
Maximum Market Size for Syngas-Derived DME and for FT Diesel as a Pure Fuels GJ per Year

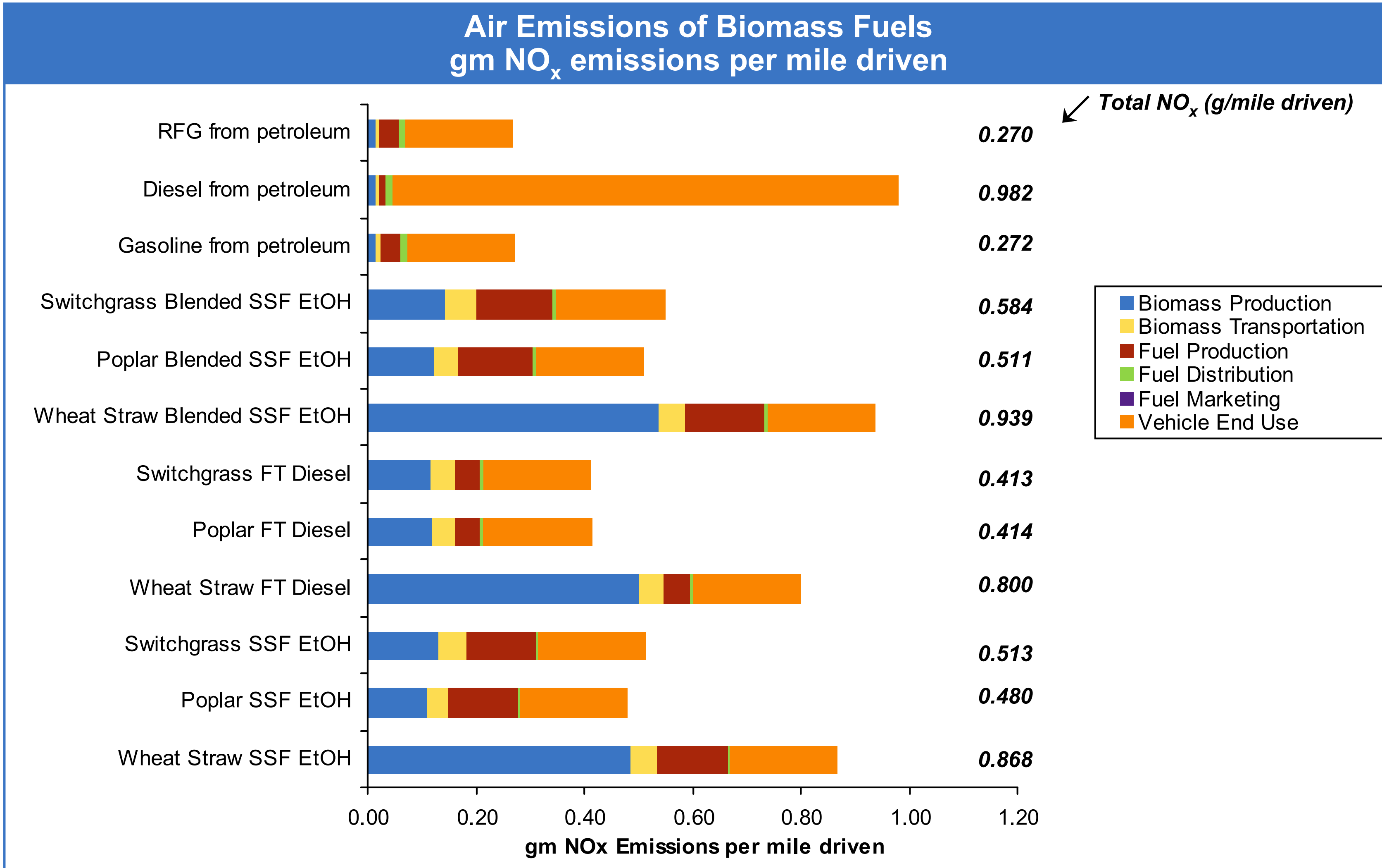


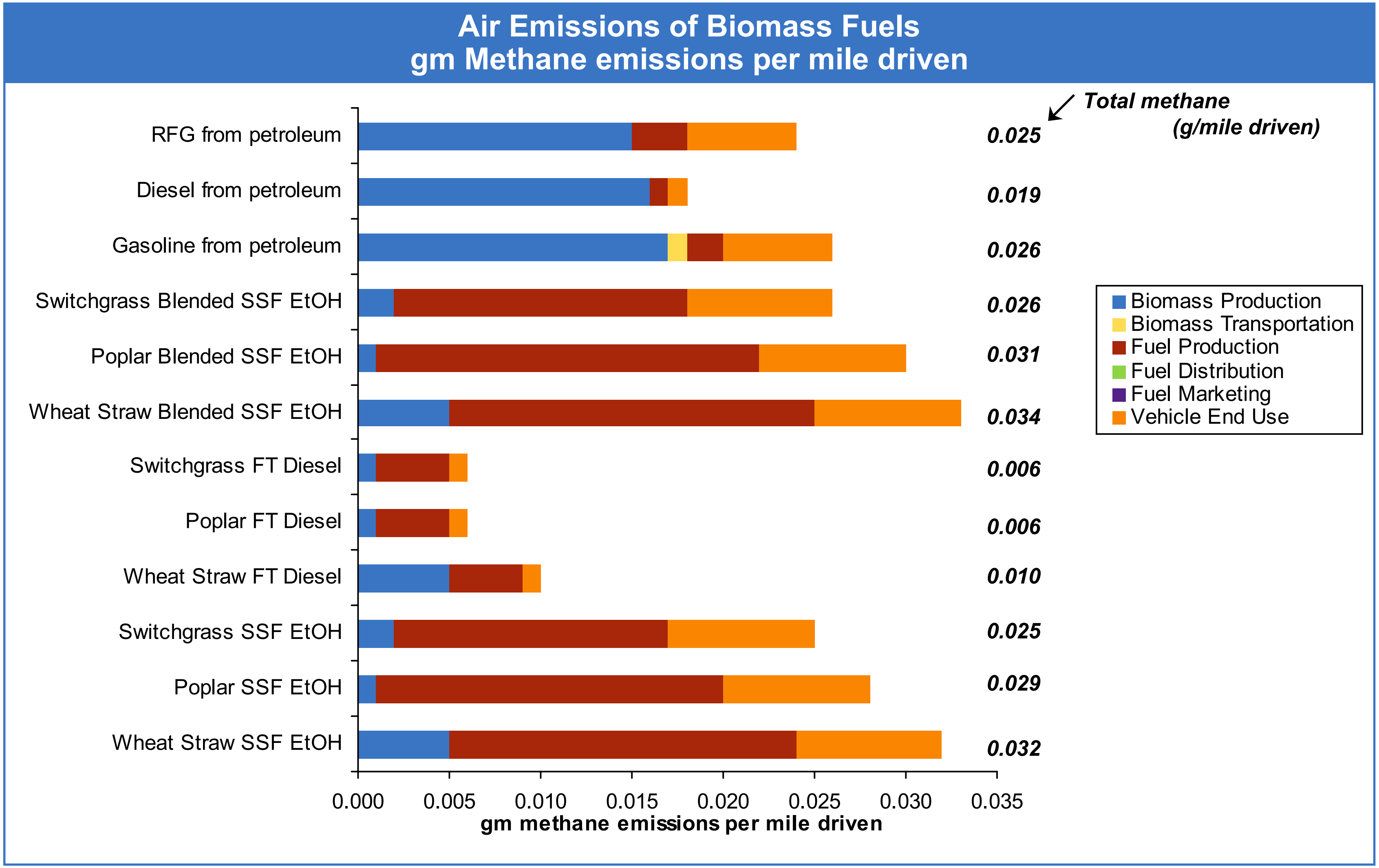
1. The bars represent using the entire resource to generate fuel.
2. DME (dimethyl ether) includes corn stover, wheat straw, switchgrass, and poplar.
3. FT Diesel (Fischer-Tropsch) includes corn stover, wheat straw, switchgrass, and poplar.
4. The following energy values have been used for the fuels: Ethanol 88.6 MJ per gal.; DME 80.4 MJ per gal; FT Diesel 138.4 MJ per gal.



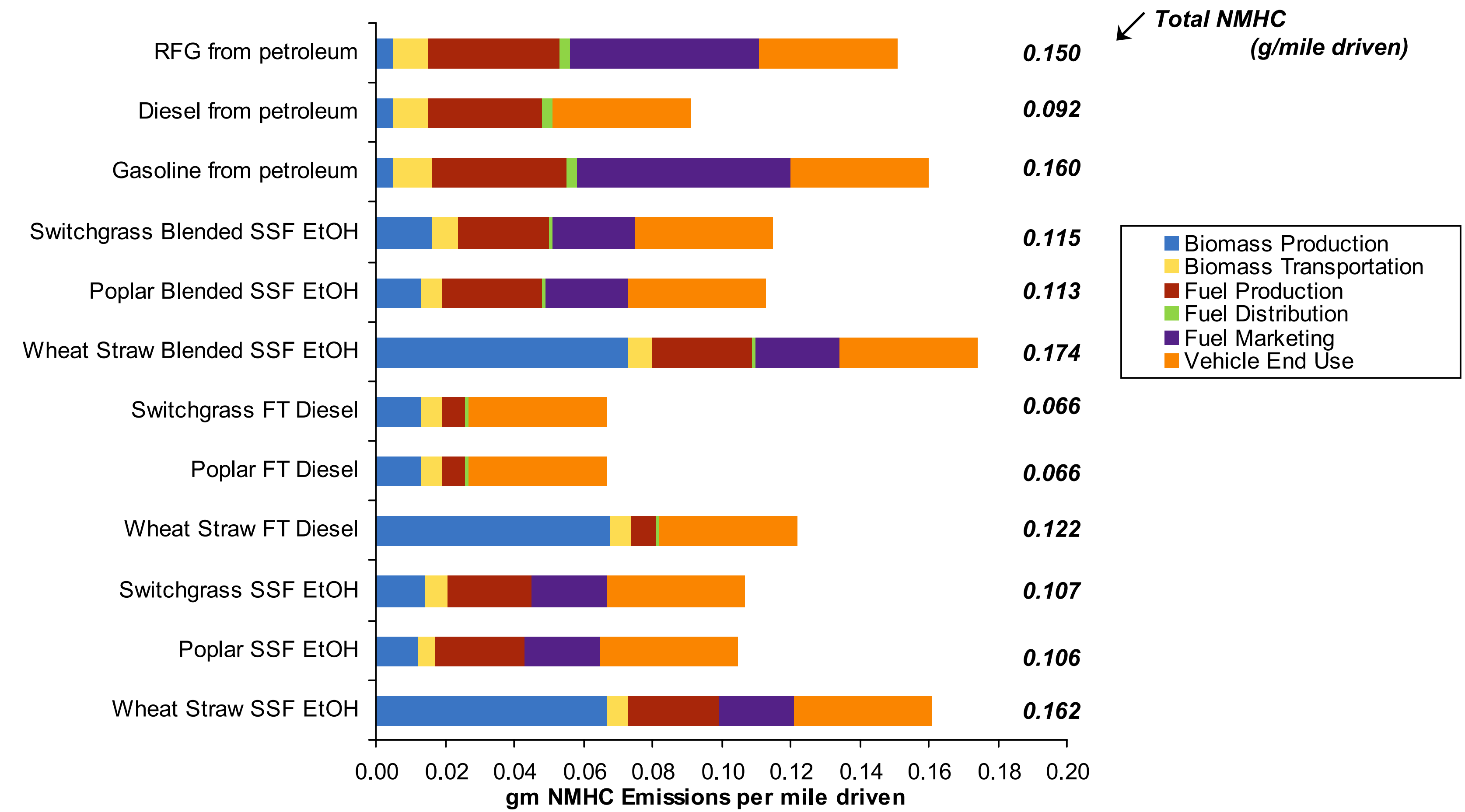
Air Emissions of Biomass Fuels
gm CO_2 emissions per mile driven
Total CO_2 (g/mile driven
RFG from petroleum
Diesel from petroleum
Gasoline from petroleum
Switchgrass Blended SSF EtOH
Poplar Blended SSF EtOH
Wheat Straw Blended SSF EtOH
Switchgrass FT Diesel
Poplar FT Diesel
Wheat Straw FT Diesel
Switchgrass SSF EtOH
Poplar SSF EtOH
Wheat Straw SSF EtOH
299
294
369
58.5
47.9
137
38.7
39.5
120
52.3
42.6
124
Biomass Production
Biomass Transportation
Fuel Production
Fuel Distribution
Fuel Marketing
Vehicle End Use
0.0
50.0
100.0
150.0
200.0
250.0
300.0
350.0
400.0
gm CO2 Emissions per mile driven

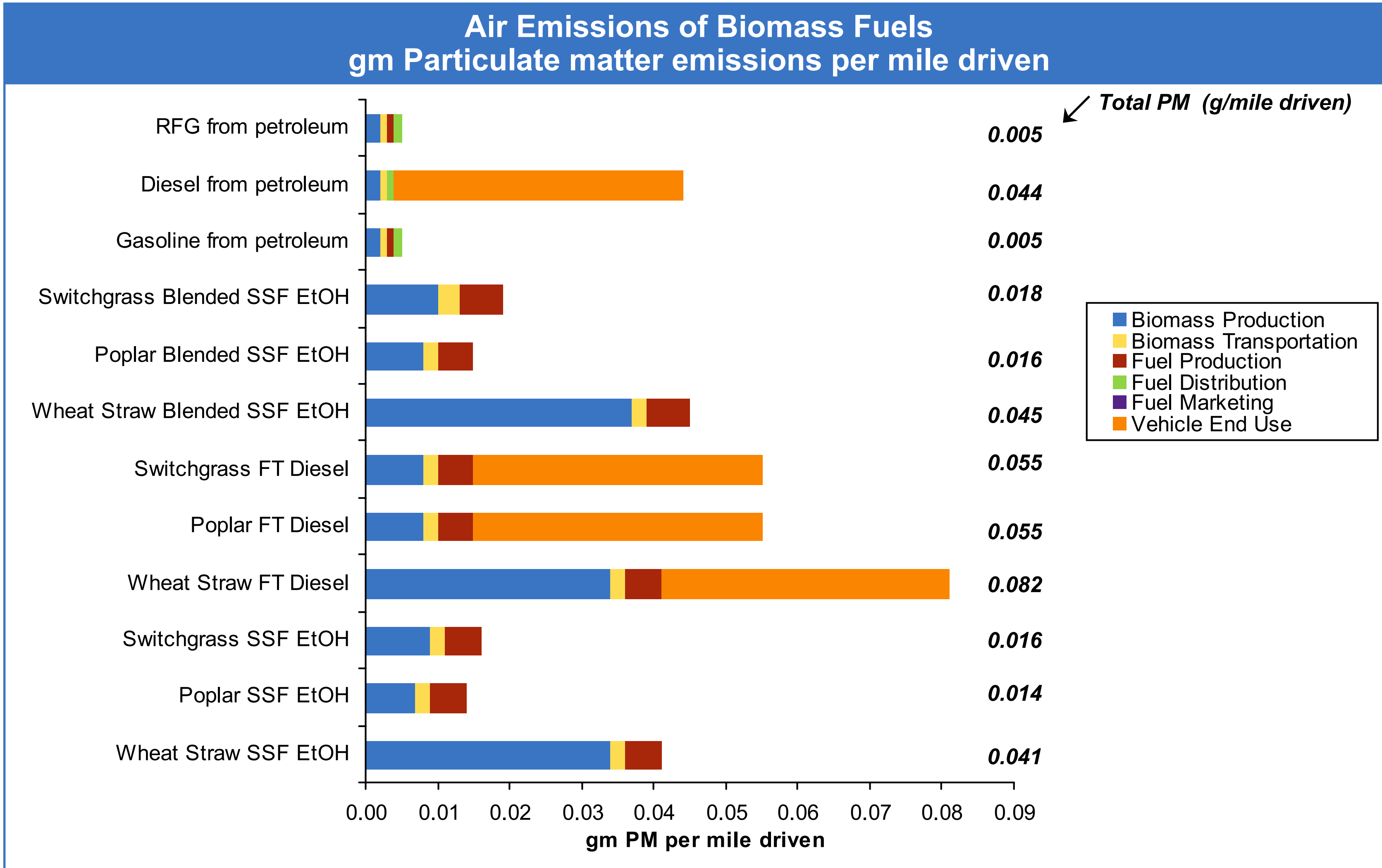

Air Emissions of Biomass Fuels
gm SO_2 emissions per mile driven
Total SO_2 (g/mile driven
RFG from petroleum
Diesel from petroleum
Gasoline from petroleum
Switchgrass Blended SSF EtOH
Poplar Blended SSF EtOH
Wheat Straw Blended SSF EtOH
Switchgrass FT Diesel
Poplar FT Diesel
Wheat Straw FT Diesel
Switchgrass SSF EtOH
Poplar SSF EtOH
Wheat Straw SSF EtOH
0.098
0.063
0.102
0.321
0.357
0.481
0.101
0.103
0.224
0.292
0.324
0.438
Biomass Production
Biomass Transportation
Fuel Production
Fuel Distribution
Fuel Marketing
Vehicle End Use
0.00
0.10
0.20
0.30
0.40
0.50
0.60
gmlSO2 Emissions per mile driven

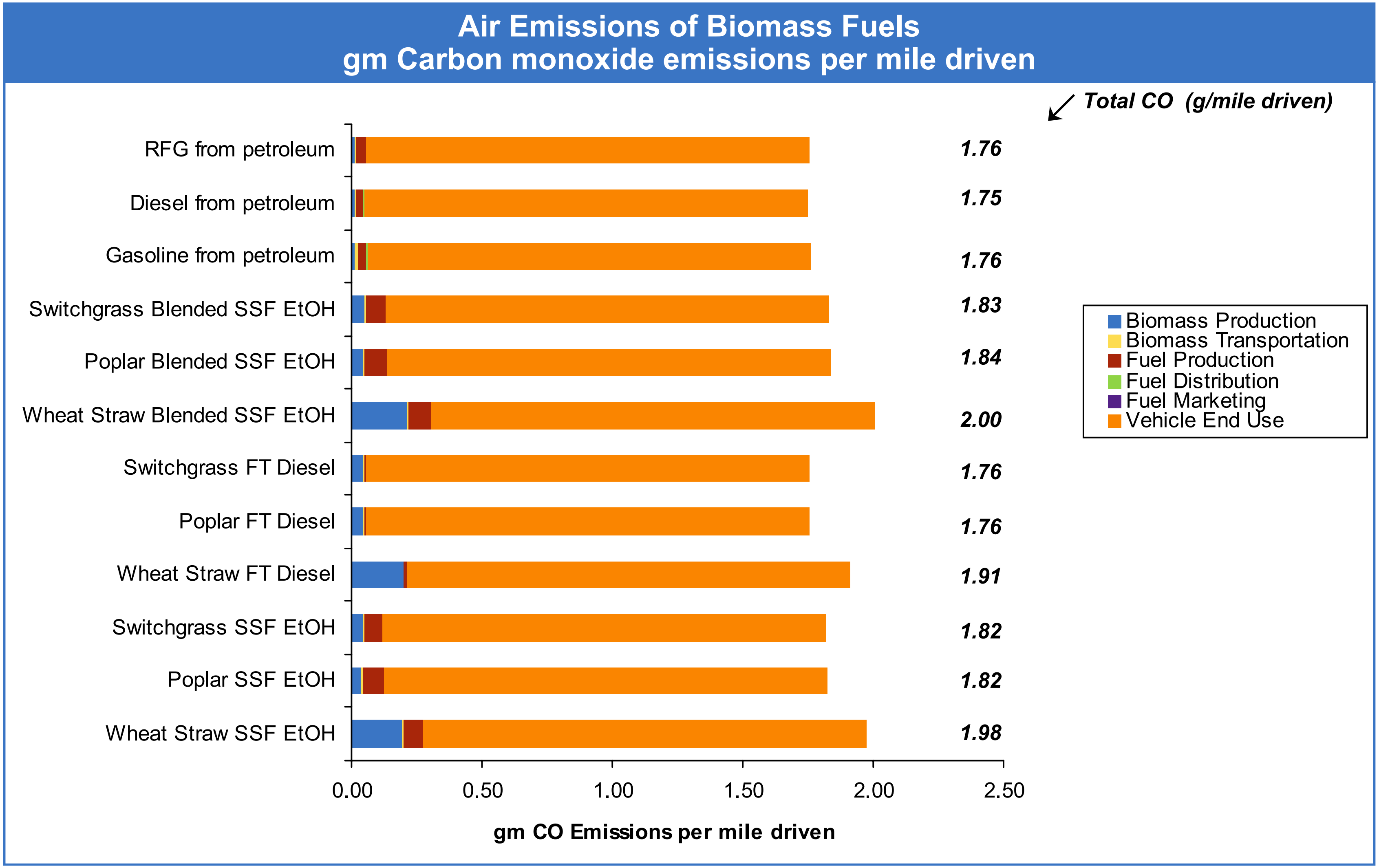

Air Emissions of Biomass Fuels
gm NOx emissions per mile driven
Total NOx (g/mile driven)
RFG from petroleum 0.270
Diesel from petroleum 0.982
Gasoline from petroleum 0.272
Switchgrass Blended SSF EtOH 0.584
Poplar Blended SSF EtOH 0.511
Wheat Straw Blended SSF EtOH 0.939
Switchgrass FT Diesel 0.413
Poplar FT Diesel 0.414
Wheat Straw FT Diesel 0.800
Switchgrass SSF EtOH 0.513
Poplar SSF EtOH 0.480
Wheat Straw SSF EtOH 0.868
Biomass Production
Biomass Transportation
Fuel Production
Fuel Distribution
Fuel Marketing
Vehicle End Use
0.00
0.20
0.40
0.60
0.80
1.00
1.20
gm NOx Emissions per mile driven


Air Emissions of Biomass Fuels
gm Methane emissions per mile driven
Total methane (g/mile driven)
RFG from petroleum 0.025
Diesel from petroleum 0.019
Gasoline from petroleum 0.026
Switchgrass Blended SSF EtOH 0.026
Poplar Blended SSF EtOH 0.031
Wheat Straw Blended SSF EtOH 0.034
Switchgrass FT Diesel 0.006
Poplar FT Diesel 0.006
Wheat Straw FT Diesel 0.010
Switchgrass SSF EtOH 0.025
Poplar SSF EtOH 0.029
Wheat Straw SSF EtOH 0.032
Biomass Production
Biomass Transportation
Fuel Production
Fuel Distribution
Fuel Marketing
Vehicle End Use
0.000 0.005 0.010 0.015 0.020 0.025 0.030 0.035
gm methane emissions per mile driven

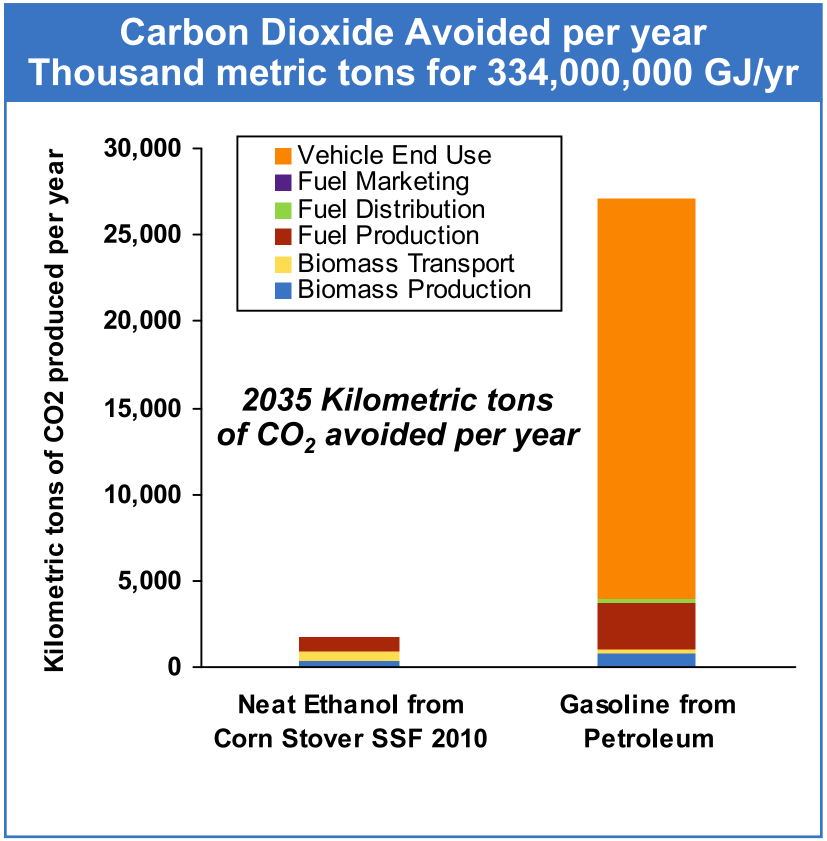
Air Emissions of Biomass Fuels
gm Non-methane hydrocarbon emissions per mile driven

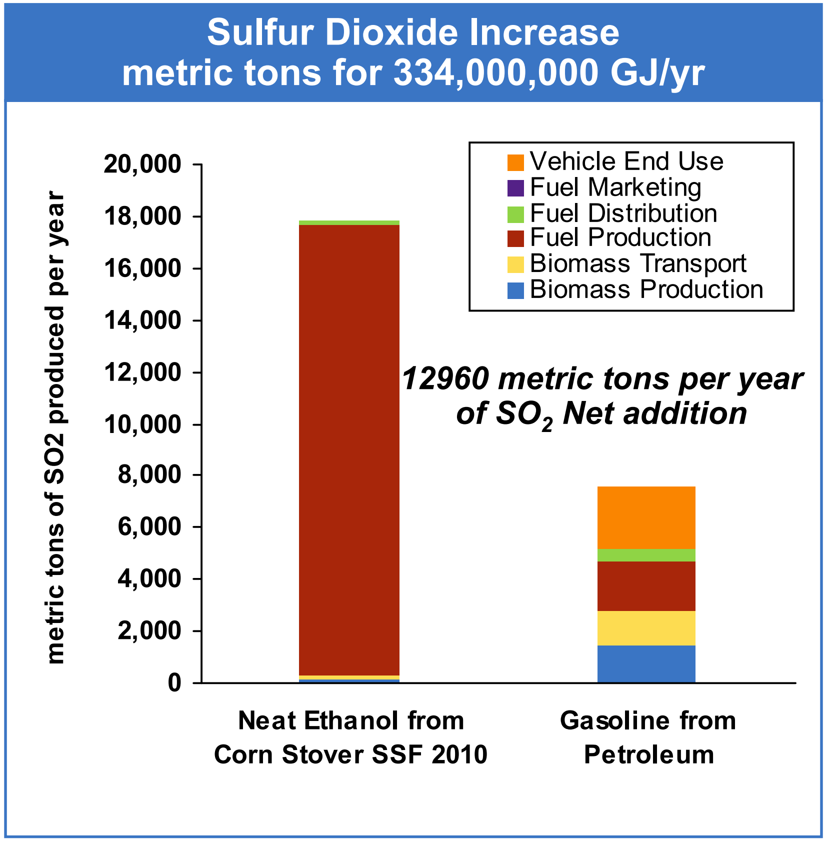



Air Emissions of Biomass Fuels
gm Particulate matter emissions per mile driven
Total PM (g/mile driven)
RFG from petroleum
0.005
Diesel from petroleum
0.044
Gasoline from petroleum
0.005
Switchgrass Blended SSF EtOH
0.018
Poplar Blended SSF EtOH
0.016
Wheat Straw Blended SSF EtOH
0.045
Switchgrass FT Diesel
0.055
Poplar FT Diesel
0.055
Wheat Straw FT Diesel
0.082
Switchgrass SSF EtOH
0.016
Poplar SSF EtOH
0.014
Wheat Straw SSF EtOH
0.041
Biomass Production
Biomass Transportation
Fuel Production
Fuel Distribution
Fuel Marketing
Vehicle End Use
0.00
0.01
0.02
0.03
0.04
0.05
0.06
0.07
0.08
0.09
gm PM per mile driven


Air Emissions of Biomass Fuels
gm Carbon monoxide emissions per mile driven
Total CO (g/mile driven)
RFG from petroleum
Diesel from petroleum
Gasoline from petroleum
Switchgrass Blended SSF EtOH
Poplar Blended SSF EtOH
Wheat Straw Blended SSF EtOH
Switchgrass FT Diesel
Poplar FT Diesel
Wheat Straw FT Diesel
Switchgrass SSF EtOH
Poplar SSF EtOH
Wheat Straw SSF EtOH
1.76
1.75
1.76
1.83
1.84
2.00
1.76
1.76
1.91
1.82
1.82
1.98
0.00
0.50
1.00
1.50
2.00
2.50
gm CO Emissions per mile driven
Biomass Production
Biomass Transportation
Fuel Production
Fuel Distribution
Fuel Marketing
Vehicle End Use

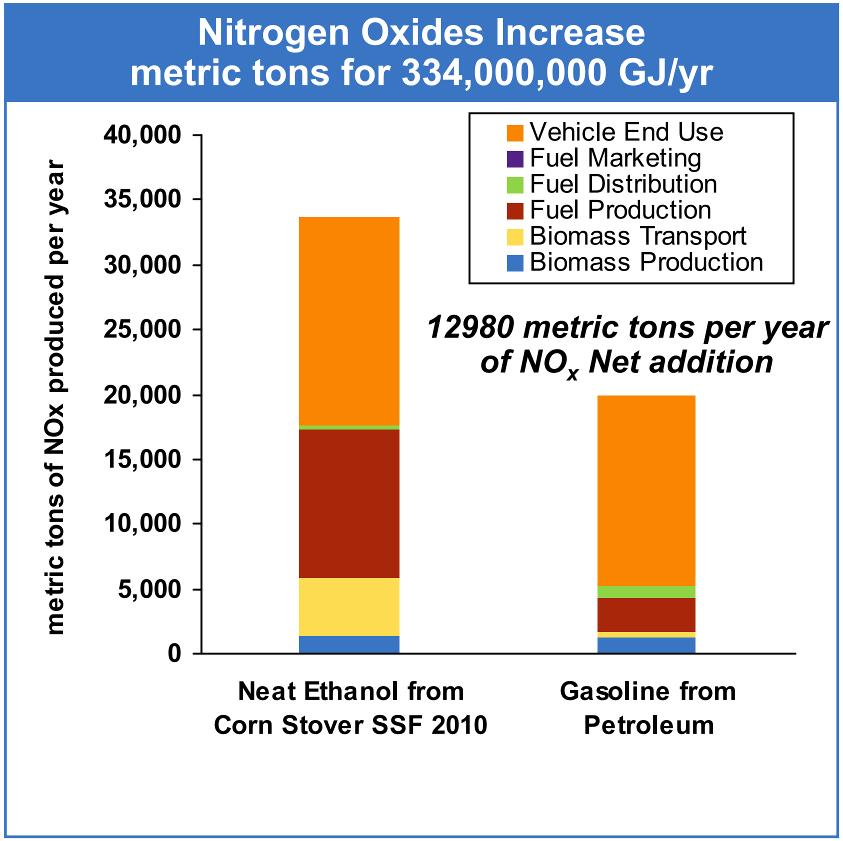
The main benefit for biofuels is in carbon dioxide reduction. Sulfur emissions benefits are negligible.





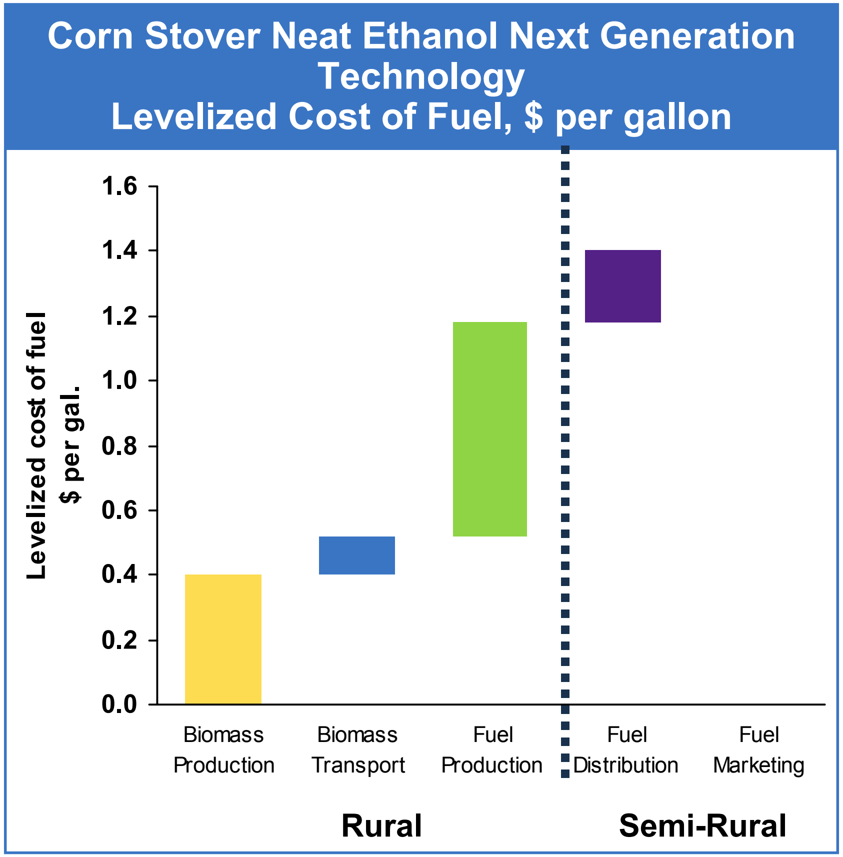
1. The Emissions shown produce a total of 334,000,000 GJ of fuel per year using a total of 50,385 Ktons per year of neat ethanol from corn stover using NREL SSF 2010

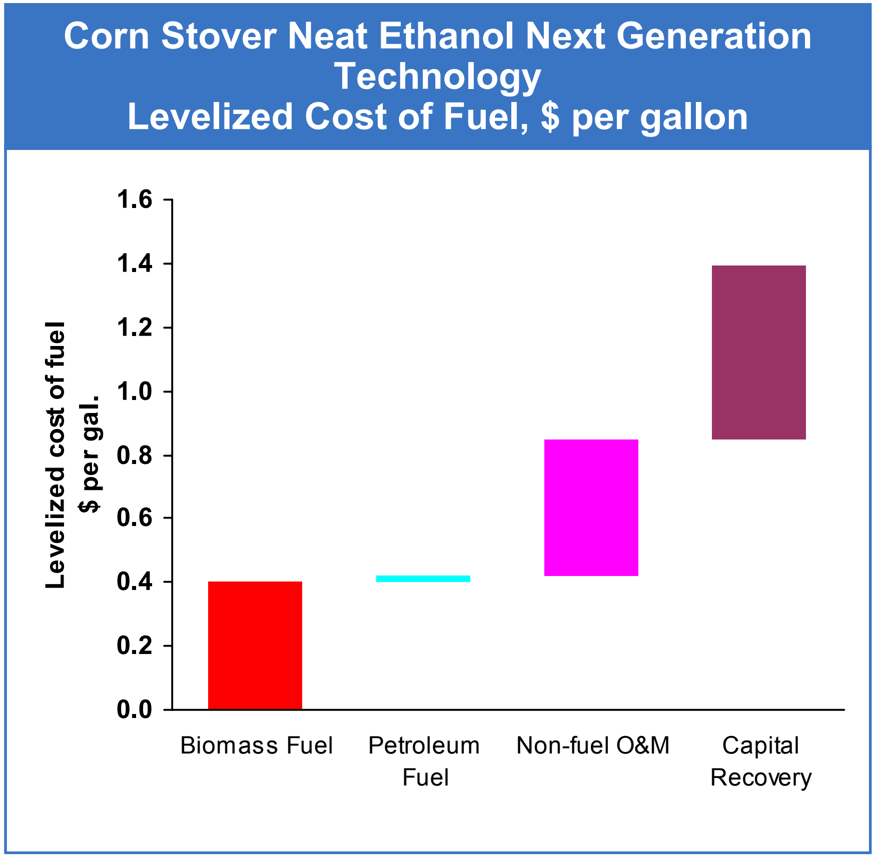
There may be a net increase in NOx if diesel engines are heavily used in the processing plants.



1. The Emissions shown produce a total of 334,000,000 GJ of electricity per year using a total of 50,385 Ktons per year of neat ethanol from corn stover using NREL SSF 2010

The bulk of the value created occurs in rural areas for cellulosic ethanol due to the economic limit of viable distance for biomass transport.

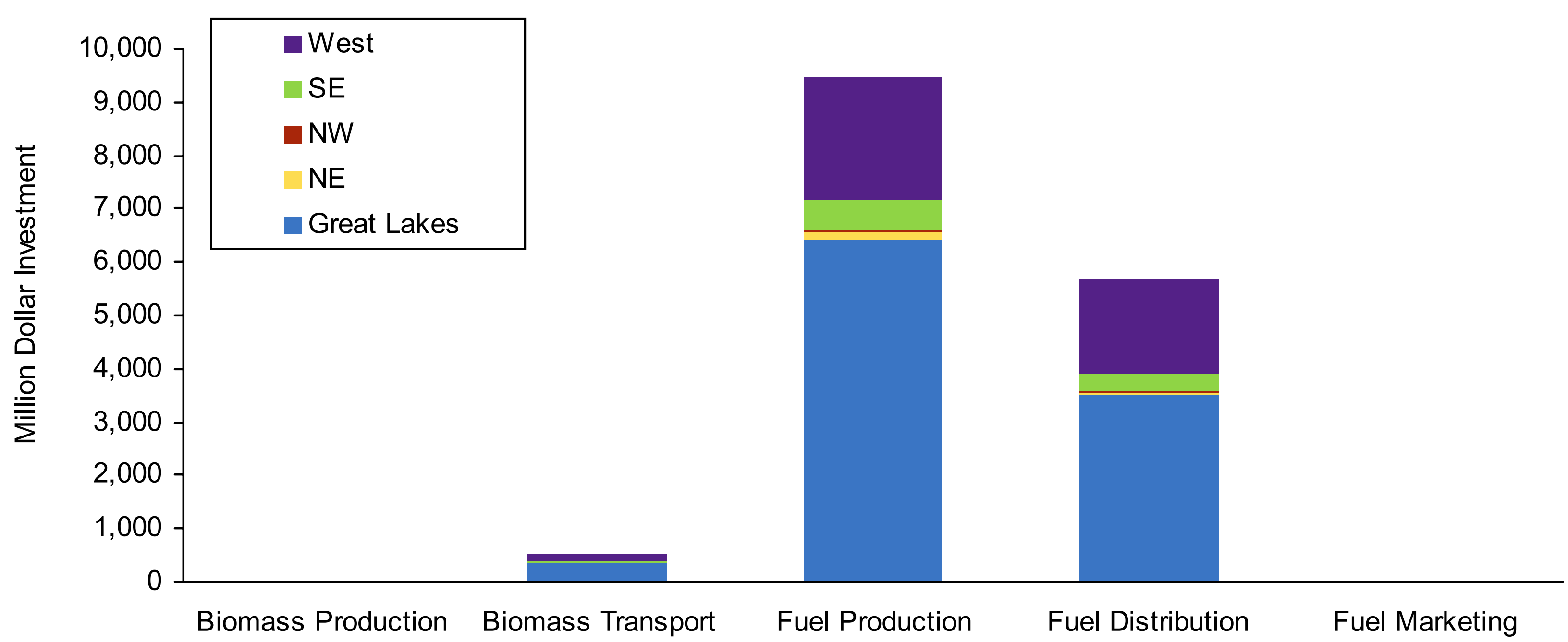




1. Capital recovery cost per year are a 13% per year for biomass transport investment and 15% for fuel production investment, 9% for fuel distribution investment, and 25% for fuel marketing. The capital recovery for biomass production is included in the price for biomass.
2. The fuel operating cost for biomass production is solely the cost of the biomass. The capital, non-fuel operating, and petroleum fuel costs in biomass production are incorporated into the price for biomass
3. The feedstock cost of corn stover is $30 per ton.

In terms of one-time investment, the bulk of the capital required will be in processing plants for cellulosic ethanol.

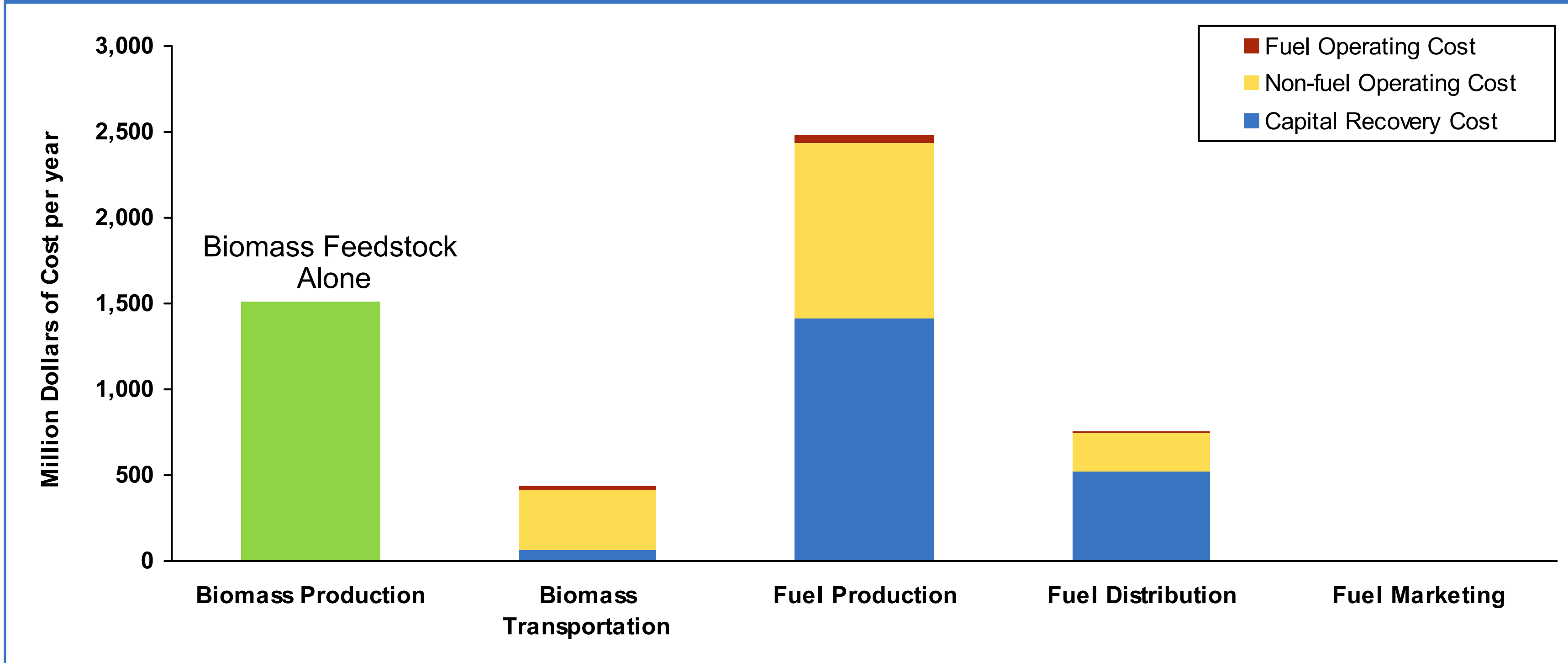
Total Capital Investment for Neat Ethanol from Corn Stover SSF 2010 Technology
Million Dollar Investment



1. The investments shown produce a total of 334,000,000 GJ of fuel per year using a total of 50,385 Ktons per year of neat ethanol from corn stover using NREL SSF 2010
2. The capital investment associated with biomass production is assume to be contained in the feedstock cost.

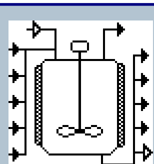
The annual costs are comparable between the cost of the biomass and the annual cost of operating the processing plants for cellulosic ethanol.

Neat Ethanol from Corn Stover 2010 Technology
Cost of Total Fuel Chain, $Millions/yr



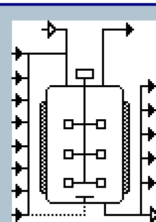
1. Capital recovery cost per year are a 13% per year for biomass transport investment and 15% for fuel production investment, 9% for fuel distribution investment, and 25% for fuel marketing.
2. The fuel operating cost for biomass production is solely the cost of the biomass. The capital, non-fuel operating, and petroleum fuel costs in biomass production are incorporated into the price for biomass
3. The feedstock cost of corn stover is $30 per ton.
4. The investments shown produce a total of 334,000,000 GJ of fuel per year using a total of 50,385 Ktons per year of neat ethanol from corn stover using NREL SSF 2010

Fermentation-derived commodity chemical products may require the adaptation of technology currently used in petrochemical production.



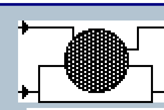
Feedstock Preparation

- Biomass processing and handling
- Recovery of fermentable fractions
- Disposal of unused fractions
- Low flexibility towards biomass type
- May use petrochemical scale processing technology



Fermentation

- Manufacture of product by organisms
- Up-keep of organisms
- Low temperature, low pressure operation
- Technology development required for petrochemical scale production technology



Cell separation

Product remains in cell or is excreted

Broth

Product Excreted (In Broth)

- Product recovery
- Product purification steps
- May use petrochemical scale processing technology

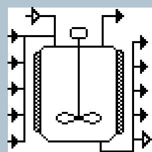
Cell Paste

Product remains in cell (cell paste)

- Multi-step processing to recover product from inside organism
- Subsequent product purification steps
- Pharmaceutical/ specialty chemical scale technology required

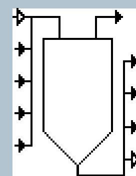
1. The sensitivity of the organism used largely determines the operating regime specifications. Key operating parameters include pH, temperature, pressure, substrate (feedstock) concentration, and allowable product concentration.
2. Fermentation processes are typically run at lower than 200°C and essentially atmospheric pressure operation.
3. May be energy self sufficient with utilization of unused feedstock portions for heat and power generation.

Pyrolysis-derived products are recovered from medium to high temperature processing of biomass feedstocks.



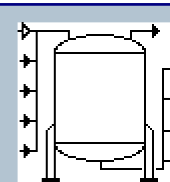
Feedstock Preparation

- Biomass processing and handling
- Pretreatment (hydrolysis or base treatment) of feedstock if required
- Maximum scale may be limited by scale of the biomass input to the plant
- Medium flexibility towards biomass type



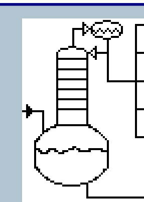
Pyrolysis

- High temperature processing of biomass
- Production of oil and gaseous product
- Scale dictated in large extent by reactor configuration required



Product recovery from pyrolysis oil

- Recovery of gaseous product (for product or internal fuel use)
- Recovery of oil product
- Removal of solid residues such as ash
- May use petroleum processing technology

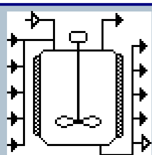


Final product upgrading and purification

- Recovery of product fractions by extraction and/or distillation operations
- Upgrading of the product fractions, may include:
  - –Hydrogenation
  - –Hydrodeoxygenation
  - –Hydrodenitrogenation
  - –Catalytic cracking
- Final product purification
- May use petroleum upgrading technology

1. The operating regime for pyrolysis is dependent upon the feedstock properties (relative fraction of lignin, cellulose and hemicellulose); required process contact or residence time, and the desired product slate
2. Pyrolysis processes are typically run at 200-800°C. Pressurized or atmospheric operation is possible.
3. May be energy self sufficient with utilization of gaseous products and char for power and heat generation, largely dependent upon product slate.

C_1-chemistry can be used to tailor products using syngas produced from gasification of the biomass.



Feedstock Preparation

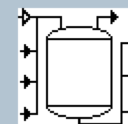
- Biomass handling
- Maximum scale may be limited by scale of the biomass input to the plant
- High flexibility towards biomass type

Biomass Gasification

- High temperature processing of biomass
- Production of syngas and permanent gases
- Possible by-products of char and tar
- Scale dictated in large extent by reactor configuration required

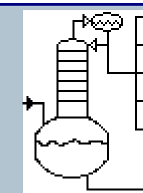
Reforming and Syngas Conditioning

- Reforming of trace unconverted hydrocarbons
- Cooling of reformate stream
- Adjustment of syngas composition (if necessary)
- May use existing syngas generation technology



Syngas Conversion

- Adjustment of syngas composition for gaseous products (e.g. hydrogen or synthetic natural gas)
- Conversion of syngas gas into liquid product (e.g. methanol, DME, FT crude)
- Liquid product synthesis usually at high pressure

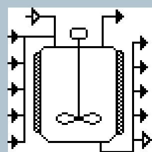


Product Upgrading

- Gaseous products may need additional pressurization for use in existing infrastructure
- Liquid fuels may require additional purification and recovery operations
- Further upgrading of products may be required (e.g. Fischer-Tropsch synthesis products)

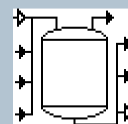
1. The operating regime for gasification is dependent upon the feedstock properties (relative fraction of lignin, cellulose and hemicellulose); required process contact or residence time, and the desired product slate
2. Reforming and syngas conditioning may be run at high pressure (10-80 bar) if liquid synthesis is performed such as methanol, DME or Fischer-Tropsch synthesis
3. Most biomass processes for liquid synthesis will require additional biomass for heat and power generation.

Low-temperature processing can be used to convert the biomass into a form which is then more easily handled by other processing techniques.



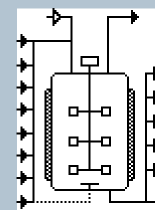
Feedstock Preparation

- Biomass processing and handling
- Pretreatment (hydrolysis or base treatment) of feedstock if required
- Maximum scale may be limited by scale of the biomass input to the plant
- Medium flexibility towards biomass type



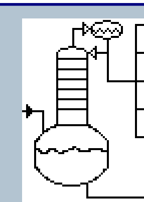
Low temperature processing

- Low temperature processing of biomass
- Use of enzymes, acid, or base to break-down biomass into constituent fractions
- Separation and recovery of constituent fractions if necessary



Further transformation of processed biomass

- Recovery of gaseous product if available (for product or internal fuel use)
- Recovery of product
- Further processing by:
  - –Chemical synthesis
  - –Fermentation

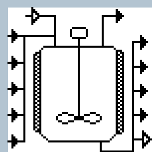


Final product upgrading and purification

- Recovery of product fractions by extraction and/or distillation operations
- Upgrading of the product fractions, may include:
  - –Fermentation
  - –Hydrogenation
  - –Hydrodeoxygenation
  - –Hydrodenitrogenation
- Final product purification

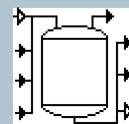
1. The operating regime for low temperature processing is dependent upon the feedstock properties (relative fraction of lignin, cellulose and hemicellulose); required process contact or residence time, and the desired product slate
2. Processes are typically run at 20-200°C and atmospheric pressure
3. The process may require require additional biomass for heat and power generation.

Extraction processing may be used when a chemical entity can be derived without significant further chemical processing of the biomass



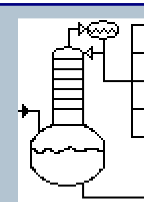
Feedstock Preparation

- Biomass processing and handling
- Pretreatment (hydrolysis or base treatment) of feedstock if required
- Maximum scale may be limited by scale of the biomass input to the plant
- Low flexibility towards biomass type



Product Recovery

- Low temperature processing of biomass
- Use of enzymes, acid, or base to break-down biomass into constituent fractions
- Separation and recovery of constituent fractions if necessary



Final product upgrading and purification

- Recovery of product fractions by extraction and/or distillation operations
- Upgrading of the product fractions, may include:
  - –Fermentation
  - –Hydrogenation
  - –Hydrodeoxygenation
  - –Hydrodenitrogenation
- Final product purification

1. The operating regime for processing is dependent upon the feedstock properties (relative fraction of lignin, cellulose and hemicellulose); required process contact or residence time, and the desired product slate
2. Processes are typically run at 20-200°C and atmospheric pressure
3. The process may require require additional biomass for heat and power generation.

Issues related to introduction of new chemicals for solvent use

Environmental regulations have put pressure on industry to replace traditional solvent systems for several years.

- Montreal Protocol
  - International treaty requiring phase-out of Ozone Depleting Products*
    - Milestones have driven the search for alternatives for many years
      - 1987: Montreal Protocol Adopted by 22 countries, including U.S.
      - 1995: “Class 1” (worst) products banned in developed world
      - 1997: “Class 2” (less aggressive) products banned in the U.S.
      - 2005: Complete global ban of all ODP’s
  - Severely impacts the use of Chlorinated solvents and Chlorofluorocarbons
    - Some of the most widely-used industrial solvents eliminated
      - 1,1,1 TCA, CFC 113, etc
      - ~1 Billion Tons/yr used by early 1980’s

* Refer to Guide to Acronyms on last page of this section.

Tightening U.S. environmental regulations have driven greater change within the domestic market.

- Clean Air Act
  - Forces reductions on volatile organic compounds (VOCs)
  - Any organic liquid is considered a VOC unless explicitly exempted
  - Large-volume, low-cost solvents are main targets
    - Paints, Inks & Coatings
      - MEK, Alcohols, MeCl, etc.
    - Low-value metal cleaning
      - Mineral spirits etc.
- National Emission Standards for Hazardous Air Pollutants (NESHAP)
  - Strictly limits permissible emissions of listed hazardous chemicals
  - List includes many traditional solvents
    - TCE, MEK, MeCl, etc.

Bio-solvents compete with several "green" alternatives all of which have been pursued vigorously, with varying success.

- Bio-solvents
- Aqueous solvent substitutes
- Biodegradable synthetics
- Closed-loop recycling of chemicals
- Combinations of all of the above

Combined regulatory pressures have fueled a race for solvent systems that are greener, cleaner, and less consumptive.

Alternative solvents must effectively replace traditional solvents while satisfying the new environmental regulations. Success criteria include:

- Performance
  - Solvency, evaporation rate, etc.
    - Equal to or better than the traditional solvent
    - Equal to or better than other competing technologies
- Cost
  - Price, longevity, disposal, special equipment, etc
    - Value-for-money proposition
    - Price-per-pound considerations
    - New equipment costs
- Ease of Use
  - Solvent system stability/maintenance
  - Equipment maintenance
  - Operator training/reformulation
- Safety

The "Holy Grail" of solvent substitutes is the "drop-in" replacement: easy to use, works in current equipment, inexpensive, and safe.

Established solvent distribution networks grew up around a few major products and key suppliers.

- Standard processes
  - Simple equipment widely available
  - Little technical support for solvent systems
- Standard products
  - Interchangeable products
  - Consistent quality among suppliers
  - High turnover of inventory
- Sales driven by
  - Relationships
  - Price
  - Service
  - Brand Loyalty

Introducing alternatives presents new challenges to the solvents distribution network.

- Technology-driven sales
  - Multiple choices in chemistry
  - Multiple choices in process
  - Requires highly trained sales force
  - Results in highly fragmented market
- New capital requirements
  - Technical support becomes critical
  - Equipment often presents limiting step
- Nonstandard products
  - Niche products for each application
  - More products to inventory
- Processes designed to be less-consumptive
  - Lower sales volumes
  - Higher inventory costs

High costs, long lead-times, and low sales volumes present significant obstacles for producers and distributors.

Bio-Solvents have both benefits and limitations not common to synthetic chemicals.

Benefits	Limitations
• "Green" image • Generally lower toxicity levels – Safer Handling – Lower cost of disposal – Less difficult remediation • Some advantage with environmental regulations • Usually readily biodegradable	• Variability in color and odor – Seasonally – Among Lots – Creates quality concerns with QC inspectors and operators • Strong or Unusual Odors – Any unfamiliar raises issues with operators, even if benign • Instability: Usually oxygenated and/or unsaturated Bio-Solvents often have issues with – Hydrolytic stability – Oxidative stability • Large price swings with agricultural commodities – e.g. d-limonene – High near $2.50/lb in 1995 – Low near $0.20/lb in 1998 • Co-produced with other materials (e.g. food, and pharmaceuticals) – Output capped by demand for unrelated products

Several types of biobased materials are marketed as solvents. Common agricultural and food byproducts have received most attention.

Commercially Important Bio-solvents

(In reverse order of commercial importance , approx.)

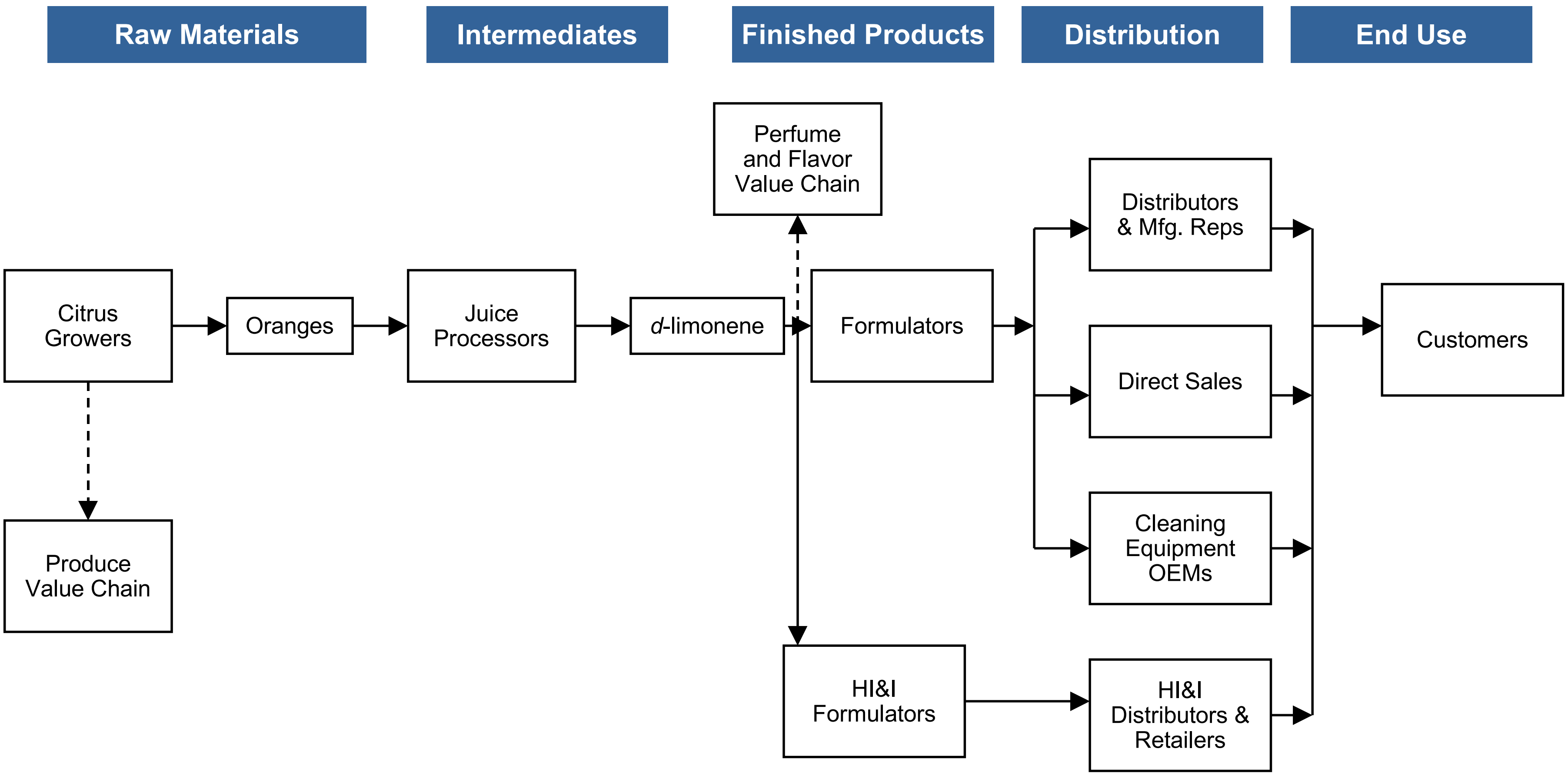
- Terpenes
  - citrus
  - pine
- Ethanol (EtOH)
- Tetrahydrofurfuryl alcohol (THFA)
- Natural Oils & Fatty Esters
  - Palmitic, Lauric, Myristic esters, etc.
  - Bio Diesel, others
- Lactic Acid Esters

Solvent use for citrus terpenes (d-limonene) is moderate to high; its barrier is mainly cost and ease of use. Odor and evaporation rate are issues for use as a fugitive solvent.

- Current Uses:
  - Industrial Cleaning
    - Automated & Manual cleaning systems for electronic assemblies
    - Degreasing
    - Parts Washers
  - HI&I Formulations

Advantages	Barriers
• Performance – Often more effective than traditional solvents • Safety (toxicity) • Aesthetics – Many users like the orange odor • Environmental – Readily biodegradable – Low treatment/disposal costs	• Cost – High price-per-pound – Requires special equipment • Ease of use – Maintenance-intensive system • Aesthetics – Pine odor can be overwhelming • Consistency – Color and odor can vary significantly among batches • Environmental: Reportable VOC

The value chain for citrus terpenes links citrus growers, specialty chemical companies, industrial distributors, direct sales forces, specifiers, and retailers in serving end users.

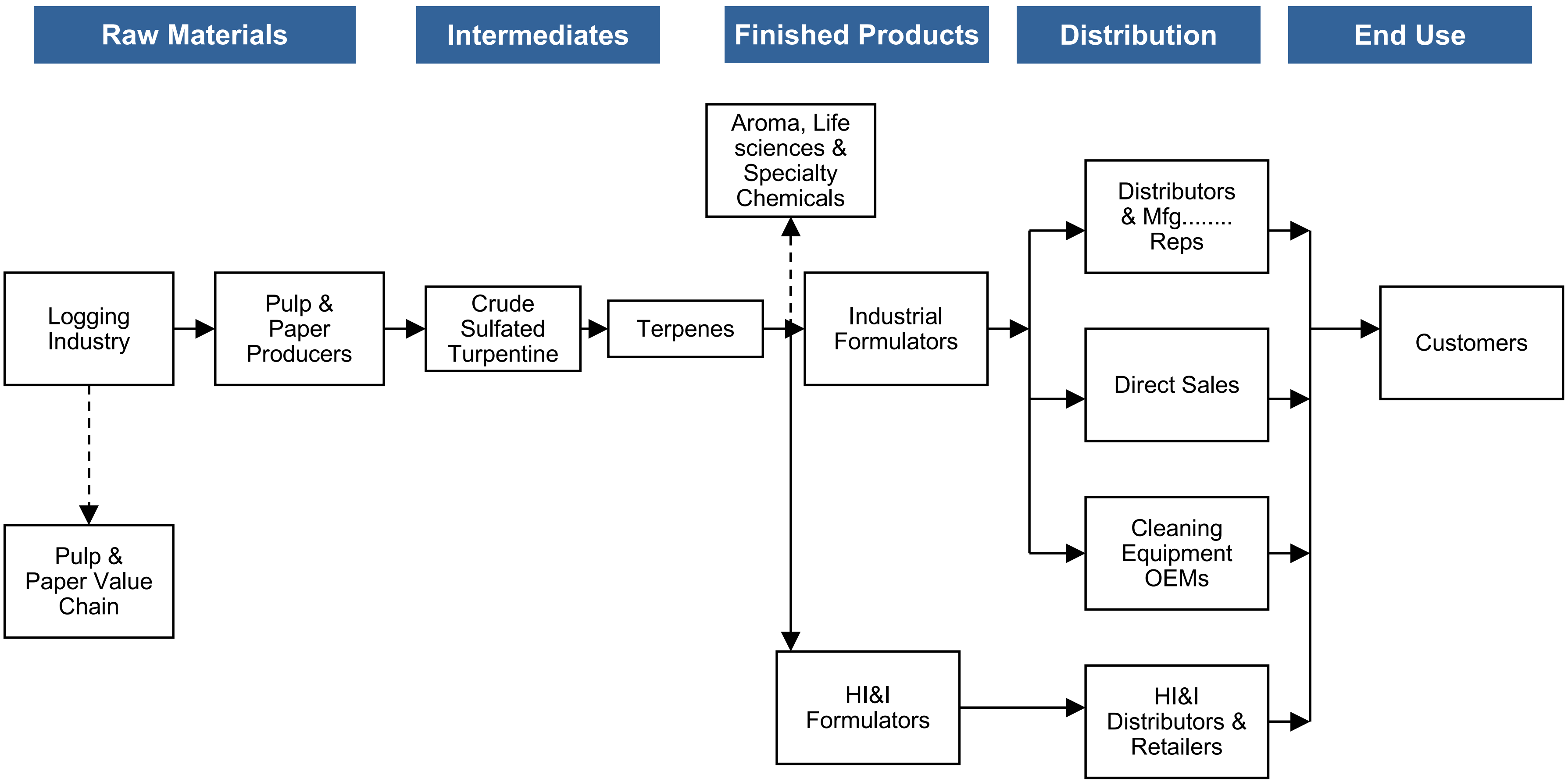


Solvent use for pine terpenes is low to moderate; its barrier is mainly cost and ease of use. Odor and evaporation rate are issues for use as a fugitive solvent.

- Current Uses:
  - Industrial Cleaning
    - Automated cleaning systems for electronic assemblies
    - Degreasing
  - HI&I Formulations

Advantages	Barriers
• Performance – Often more effective than traditional solvents • Safety (toxicity) • Aesthetics – Many users like the pine odor • Environmental – Readily biodegradable – Low treatment/disposal costs	• Cost – High price-per-pound – Requires special equipment • Ease of use – Maintenance-intensive system • Aesthetics – Pine odor can be overwhelming • Consistency – Color and odor can vary significantly among batches • Safety – Instability can lead to rag fires • Environmental: Reportable VOC

The value chain for pine terpenes links loggers, paper producers specialty chemical companies, industrial distributors, direct sales forces, specifiers, and retailers in serving end users.

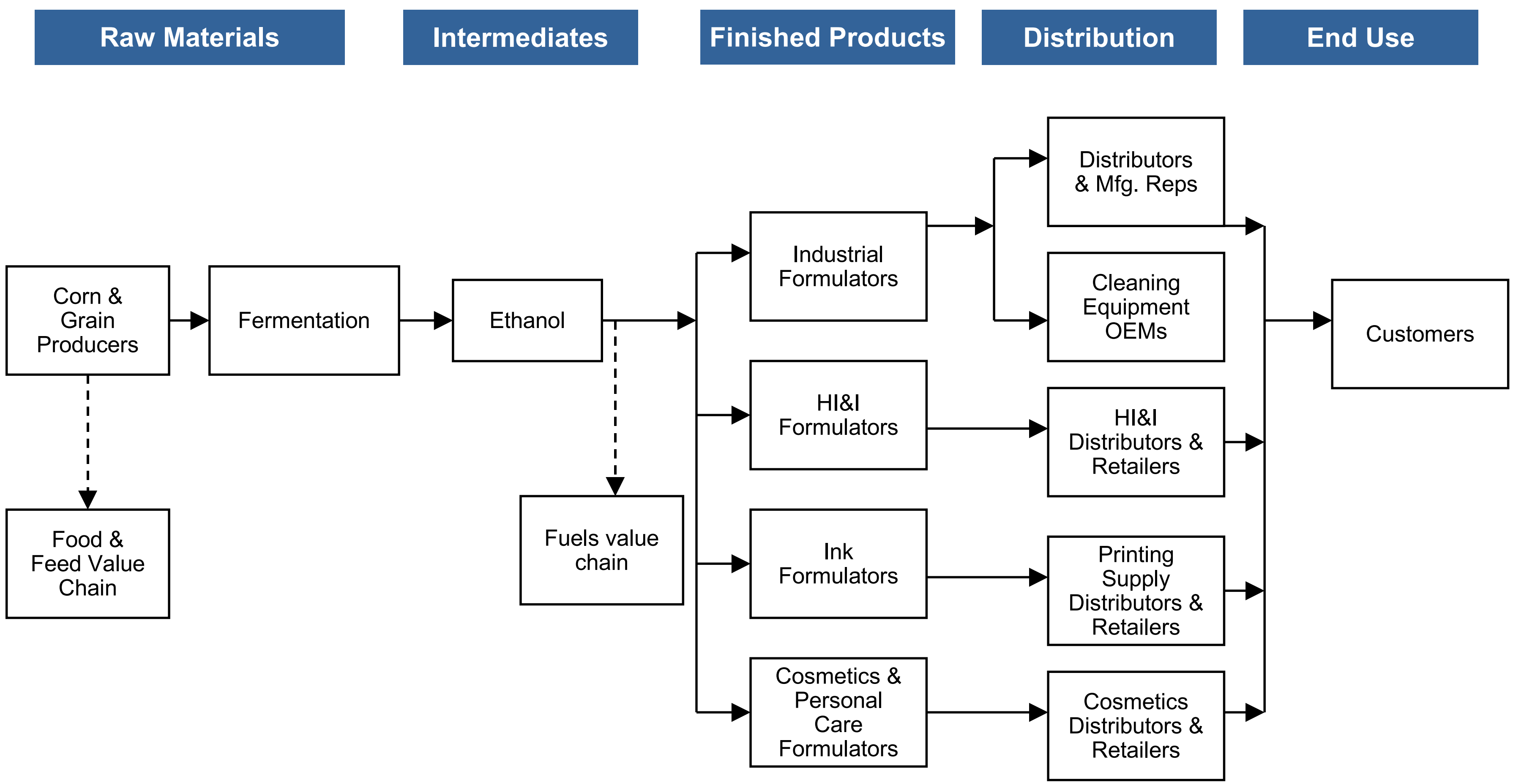


The use of ethanol as a solvent is low to moderate; its main barrier is volatility and solvency, cost and safety.

- Current Uses:
  - Inks, Coatings
    - Diluent/carrier (relatively minor use)
  - HI&I Formulations
  - Cleaning
    - Manual cleaning (low-volume)

Advantages	Barriers
• Readily available from agricultural sources • Familiar odor • Ease of use- similar to other alcohols • Safety (toxicity)	• Performance (evaporation rate & solvency) – Relative to petroleum distillates – Relative to other alcohols • Cost – Relative to petroleum distillates – Relative to other alcohols • Safety (flammability) – Relative to some traditional solvents • Ease of Use – Explosion proof equipment for large applications • Environmental: Reportable VOC

Ethanol is used in limited quantities, in a wide variety of applications.

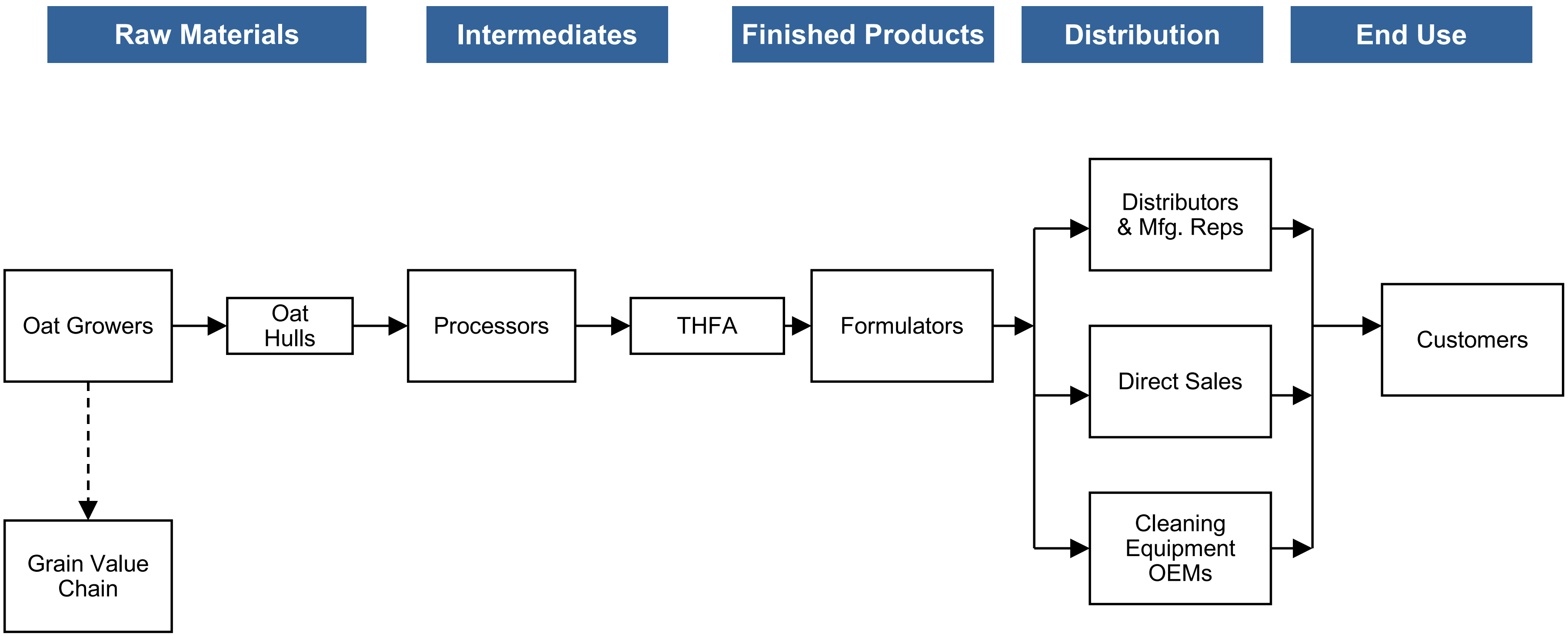


Tetrahydrofurfuryl alcohol (THFA) has a low to moderate use as solvent. Its main barriers to use is cost,ease of use, volatility and toxicity.

- Current Uses:
  - Industrial Cleaning
    - Automated cleaning systems for electronic assemblies

Advantages	Barriers
• Readily available from agricultural sources • Performance – More effective than traditional solvents • Safety (flammability)	• Cost – High price-per-pound – Requires special equipment – High treatment/disposal costs • Ease of use – Maintenance-intensive system • Environmental: Reportable VOC • Safety: Toxicity

Tetrahydrofurfuryl alcohol (THFA) is not used widely as a solvent. Patents covering the main industrial uses keep the value chain narrow.

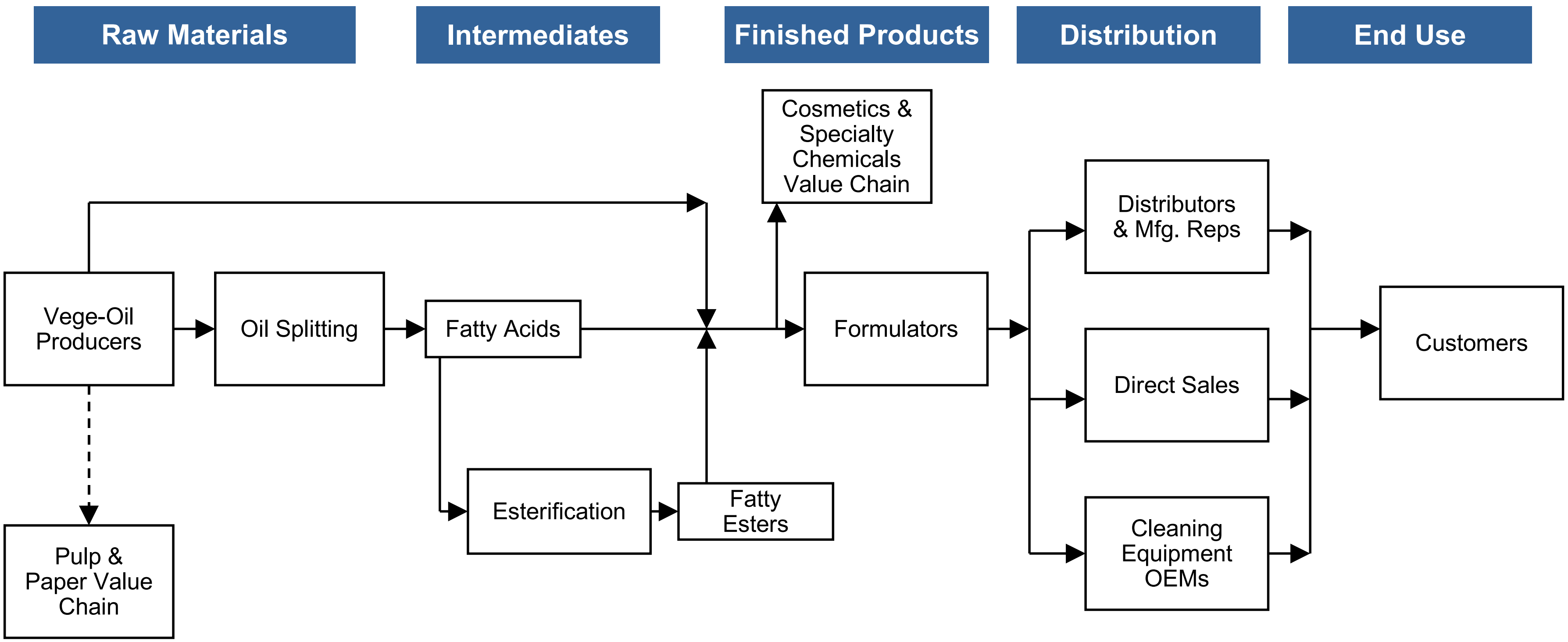


The use of Vege-Oils (Plant oils and their fatty esters) for solvents is low; its main barrier is cost and ease of use.

- Current Uses:
  - Industrial Cleaning
    - Automated cleaning systems for electronic assemblies
    - Degreasing

Advantages	Barriers
• Performance/Cost – Extremely high soil-loading capacities • Safety – Toxicity – Flammability • Aesthetics – Low odor • Environmental – Readily biodegradable – Low treatment/disposal costs	• Cost – High price-per-pound – Requires special equipment • Ease of use – Maintenance-intensive system • Performance – Limited applications due to mild solvency • Environmental: Reportable VOC

Vege-Oils and their derivatives are used in solvent formulations at several stages of refinement.



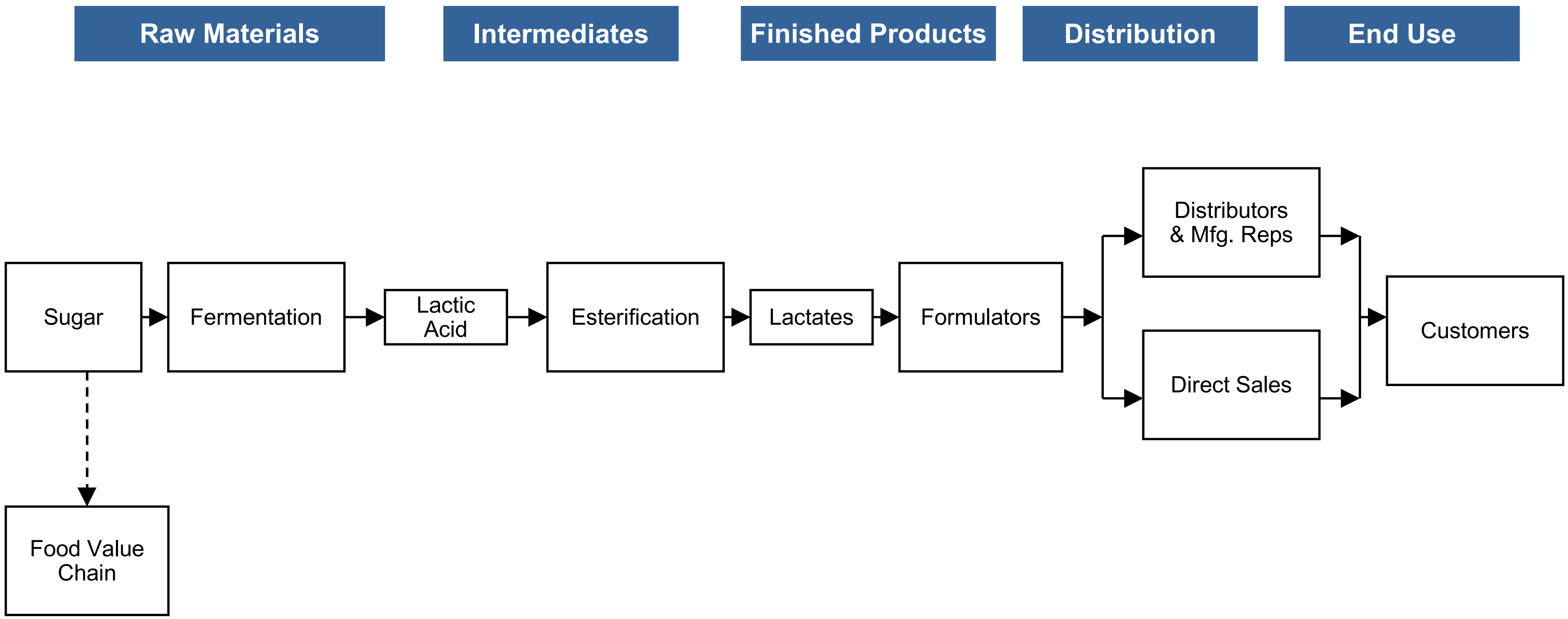
The use of Lactic acid esters for a solvent is minimal; its main barrier is cost and aesthetics.

- Current Uses:
  - Industrial Cleaning
    - Automated & Manual cleaning systems for electronic assemblies

Advantages	Barriers

• Availability of raw materials
• Safety
  – Toxicity
	• Cost
	  – High price-per-pound
	• Aesthetics
	  – Offensive odor severely limits acceptance among users
	• Environmental: Reportable VOC

Lactates are not used widely as solvents due to odor and relatively high cost; accordingly, the value chain is narrow.



Guide to acronyms

CFC	Chlorofluorocarbon
ODP	Ozone Depleting Product
VOC	Volatile Organic Compound
1,1,1-TCA	1,1,1-Trichloroethane
TCE	Trichloroethylene
MeCl	Methylene Chloride
EtOH	Ethanol
THFA	Tetrahydrofurfuryl alcohol
NESHAP	National Emissions Standards for Hazardous Air Pollutants

BIGCC	Biomass integrated gasification combined cycle, power generation technology
BL	Black Liquor (common term for spent kraft pulping liquor in pulp & paper industry)
C&D	Construction and demolition
CFCP	California Fuel Cell Partnership (partnership of fuel cell developers, vehicle OEMs, and fuel suppliers focused on demonstrating the feasibility of FCVs as an option to meet the California ZEV mandate)
CNG	Compressed natural gas, e.g. Pressurized natural gas
DOE	Department of Energy (United States)
DME	Dimethyl ether
DMM	Dimethoxy methane
dt	dry ton
EIA	Energy Information Administration (United States)
EPA	Environmental Protection Agency (United States)
EtOH	Ethanol
ETBE	Ethyl tertiary-butyl ether
FCV	Fuel Cell Vehicle
FT	Fischer-Tropsch (carbon polymerization process developed in the 1920's which produces paraffin mixtures that can be split into fungible petroleum-like products)
g/scf	grams per standard cubic foot
HDV	Heavy duty vehicle (e.g. trucks, buses)
IPP	Independent Power Producer
LDV	Light duty vehicle (primarily personal automobiles, pick-up trucks, minivans, SUVs)
LNG	Liquefied natural gas
lb/bu	pounds per bushel

MeOH	Methanol
MSW	Municipal solid waste
MTBE	Methyl tertiary-butyl ether
NREL	National Renewable Energy Laboratory (United States)
ORNL	Oak Ridge National Lab (United States)
P&P	Pulp & Paper
PURPA	Public Utility Regulatory Policy Act
Quad	10^{15} BTUs or 1.054 Exajoule (10^{18} Joule)
RDF	Refuse derived fuel
U.S.	United States of America
USDA	United States Department of Agriculture
UTR	Urban tree residues
WTE	Waste to Energy (term used for waste incinerators)
ZEV	Zero Emission Vehicle

C&D	Construction and demolition
DOE	Department of Energy (United States)
dt	dry ton
EIA	Energy Information Administration (United States)
EPA	Environmental Protection Agency (United States)
g/scf	grams per standard cubic feet
lb/bu	pounds per bushel
MSW	Municipal solid waste
NREL	National Renewable Energy Laboratory (United States)
ORNL	Oak Ridge National Laboratory (United States)
U.S.	United States of America
USDA	United States Department of Agriculture
UTR	Urban tree residues

NAICS codes used

- 325221 Manufactured cellulosic fibers
- 325191 Gum and wood chemicals
- 325199 All other basic organic chemicals
- 324110 Refined petroleum products
- 324191 Petroleum lubricating oils and greases
- 325182 Carbon black
- 325222 Manufactured noncellulosic fibers

Definitions

- Cellulose ethers include: carboxymethylcellulose, carboxymethyl hydroxyethylcellulose, ethyl cellulose, ethyl hydroxyethylcellulose, hydroxybutyl methyl cellulose, hydroxyethylcellulose, hydroxyethyl methylcellulose, hydrophobically modified hydroxyethylcellulose, hydroxypropyl cellulose, hydroxypropyl methylcellulose, methyl cellulose
- Cellulose acetate includes cellulose acetates, cellulose diacetates, and triacetates
- Epoxy resins includes epichlorohydrin-bisphenolA resins; phenoxy resins; epoxy-phenol, epoxy-cresol, epoxy-resorcinol novolac resins; methyl epichlorohydrin-bisphenolA resins; cycloaliphatic epoxy resins; other epoxy resins produced from organic chemicals and designed to be cross-linked or cured with epoxy curing agents or catalysts; reactive diluents that are an integral part of the resins as sold
- Propylene glycols includes 1,2- and 1,3 propylene glycols ($C_3H_8O_2$)

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